PETROLEUM RECOVERY INSTITUTE

MEASUREMENTS AND ESTIMATION OF THREE-PHASE RELATIVE PERMEABILITY

(PART OF ENERGY, MINES AND RESOURCES COST SHARED ENERGY CONVERSION PROGRAM AND PART OF THE PROGRAM OF THE FEDERAL PANEL ON ENERGY R & D (PERD))

FINAL REPORT

BY

B.B. MAINI, F. NICOLA, J. GOLDMAN AND H.K. SARMA

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EXECUTIVE SUMMARY

This report presents the results of an experimental investigation of three-phase relative permeability at elevated temperatures and pressures. The objectives of this work were: (i) to review the previous measurements of three-phase relative permeability; (ii) to improve the reliability of steady-state three-phase (oil/water/gas) relative permeability measurements at elevated temperatures and pressures; and (iii) to examine the feasibility of using an unsteady-state method for such measurements.

The literature on experimental studies of three-phase relative permeability was reviewed in an effort to understand the reasons behind the apparent lack of agreement between different studies. The review showed that the conflicts between different studies stem primarily from the differences in experimental techniques and the differences in rocks and fluids used. Although the accuracy of such measurements has improved with improvements in the instrumentation, the techniques remain tedious and not well suited for measurements with the actual reservoir materials at reservoir conditions. There is an obvious need for improving the reliability and speed of three-phase relative permeability measurements.

In this study several improvements were made in an existing apparatus for steady-state three-phase relative permeability measurements at elevated temperatures and pressures. An end effect absorbing section was incorporated in the core holder to reduce the error caused by capillary end effects. The reliability of saturation measurements was improved by using an electrical resistivity method for the water saturation measurements. A computer based data acquisition system was incorporated to facilitate data recording.

The improved apparatus was used for a series of steady-state three-phase relative permeability tests in Ottawa sand. The three-phase water relative permeability was found to depend only on the water saturation and it was insensitive to the direction of saturation change. The gas relative permeability under three-phase flow conditions was a function of gas saturation alone and showed small but significant hysteresis. The oil relative permeability varied with saturations of all fluid phases. The hysteresis in oil relative permeability was insignificant.

The measured values of oil relative permeability were tested against a recently reported modification of Stone's model I correlation. The correlation provided a satisfactory fit of the experimental data.

An unsteady-state method of measuring three-phase relative permeability was developed. This method uses core displacement experiments involving simultaneous injection of water and gas to displace the oil. The relative permeability is calculated from the fluid production and pressure drop data recorded during the displacement experiment.

Several unsteady-state displacement tests were carried out to define the oil relative permeability over a wide region. The unsteady-state results were compared with the steady-state measurements obtained on the same system. Although there were some discrepancies, for most parts the two techniques provided similar results.

SOMMAIRE EXECUTIF

Ce rapport présente les résultats d'une étude sur la perméabilité relative d'un système à trois phases, à des pressions et températures élevées. Les objectifs de ce travail furent: (i) la révision de données provenant d'études antérieures sur la perméabilité relative d'un système à trois phases; (ii) d'améliorer la fiabilité des résultats obtenus par les régimes permanents à trois phases (huile/eau/gaz) à haute température et pression; et (iii) d'examiner la possibilité d'utiliser la méthode de régime transitoire pour obtenir ces données.

Afin de mieux comprendre les incohérences entre les études menées jusqu'à maintenant, on procéda à une révision de la littérature concernant la perméabilité relative en phase triple. Cette révision démontra que les causes principales de ces inconsistances proviennent des différentes techniques expérimentales ainsi que les milieux poreux et les fluides utilisés. Même si la précision de ces études s'améliore constamment, grâce au raffinement de l'instrumentation, les techniques restent, cependant, compliquées et difficile d'application au réservoirs pétroliers. Il y a donc un besoin évident d'améliorer la fiabilité des techniques et de réduire le temps consacré à l'obtention des données.

Un appareil amélioré pouvant mesurer la perméabilité relative en régime permanent, pour un système à trois phases, à haute température et pression, fut développé. Parmi les améliorations on y trouve: l'inclusion d'une section capable d'absorber les effets d'extrémités des carottes confinées par leurs enceinte de pression. On améliora la fiabilité de la détermination de la saturation d'eau en utilisant la méthode de résistance électrique. Enfin, on incorpora un système d'acquisition des données informatisé.

Cet appareil amélioré fut utilisé pour une série de tests sur la perméabilité relative en régime permanent, en utilisant du sable d'Ottawa comme milieu poreux. On trouva que la perméabilité relative de l'eau, en phase triple, dépend seulement de la saturation d'eau et ne réagit pas au changement de direction de la saturation. La perméabilité relative de la phase gazeuse fut affectée uniquement par la saturation du gaz et démontra une petite mais importante hystérésis. La perméabilité relative de l'huile varia en fonction des saturations de toutes les phases fluides. L'hystérésis sur la perméabilité relative de l'huile ne fut pas considérée comme importante.

Les résultats furent comparés avec une corrélation du modèle I de Stone qui fut récemment publiée. La corrélation se conforma de façon satisfaisante aux données expérimentales.

Une méthode à régime transitoire, capable de mesurer la perméabilité relative en phase triple, fut également développée. Cette méthode utilise des déplacements en milieu poreux, impliquant l'injection simultanée d'eau et de gaz dans le but de déplacer l'huile. La perméabilité relative est calculée à partir de la production de fluide et de la pression

différentielle enregistrée lors du déplacement.

Plusieurs déplacements, en régimes transitoires, furent effectués pour tenter de définir la perméabilité relative de l'huile sur une base élargie de saturation. Les résultats obtenus en régime transitoire furent comparés avec ceux obtenus en régime permanent. Même s'il y a quelques différences, les deux techniques nous donnent, pour la plupart, des résultats similaires.

INTRODUCTION

Petroleum production often involves simultaneous flow of three immiscible fluids through subterranean porous rock formations. Examples of recovery processes involving such three-phase flow include; alternating gas and water injection, steam drive, in-situ combustion, and immiscible gas injection in presence of mobile water. Thorough analysis of these processes is impossible without reliable three-phase relative permeability data. Reservoir simulation programs incorporate one or several techniques for estimating three-phase relative permeabilities, which permit three-phase simulation studies to be carried out with input of only two-phase relative permeabilities. However such simulation studies may be no more reliable than the techniques for estimating three-phase relative permeabilities employed in them. Unfortunately, the reliability of these estimation techniques can not be tested without availability of extensive experimental data on three-phase relative permeabilities

Compared to the wealth of information available in the literature on two-phase relative permeabilities, there is a dearth of experimental studies on three-phase flow through porous media. Virtually no information is available on three-phase relative permeabilities in intermediately-wet or oil-wet systems. Effects of variables such as; contact angles, viscosity ratios, interfacial tension, flood velocity and temperature on three-phase relative permeability have not been investigated. There is an obvious need for more experimental investigations of three phase relative permeabilities to resolve some of the uncertainties concerning the effects of variables mentioned above.

The reason for this scarcity of experimental data on three-phase relative permeabilities appears to be the effort and time required for such measurements. The only well accepted technique for such measurements is the steady-state method. Between 50 to 100 steady-state measurements are required to fully define the relative permeability characteristics of a given system for one direction of saturation change. It often takes 24 hours or more to reach steady state conditions for each such measurements. Combined with the time involved in

core preparation and periodic extractions to overcome the problem of error accumulation the total effort involved is indeed formidable. If the hysteresis effects corresponding to various possible directions of saturation change are also to be evaluated, the task becomes even more onerous.

Three-phase relative permeabilities play a central role in analysis of steam drive process for heavy oil recovery. Unfortunately, no experimental data is available on three-phase flow involving heavy oils at high temperatures. Several reported studies on the effect of temperature (Maini et al., 1888,1987, 1985; Torabzadeh and Handy, 1984; Quitteier and Corre, 1986; Bennion et. al. 1985) on two-phase oil/water relative permeabilities show significant temperature effects. Similar effects can be expected in two-phase oil/gas relative permeabilities also. The three-phase flow is a relatively more complex process. When considering the possible mechanisms of temperature effects on three-phase relative permeabilities, one has to deal with relative magnitudes of three contact angles (oil-water, oil-gas and water-gas), three interfacial tensions and two viscosity ratios. It is therefore probable that the effects of temperature on three-phase relative permeabilities will be more complex than the two-phase case. Whether or not this is the case can only be determined by experimental evaluations of the effects of temperature on three-phase relative permeabilities. Before this can occur the problem of developing techniques for reliable measurement of three-phase relative permeabilities at elevated temperatures and pressures has to be addressed.

The objectives of this work were to develop a reliable apparatus capable of measuring three-phase relative permeabilities at elevated temperatures and pressures. Another objective was to develop a faster alternate to the steady-state technique for three-phase relative permeability measurements. Therefore, an extension of the two-phase unsteady-state method to three-phase measurements was evaluated.

Both the steady-state and unsteady state three-phase relative permeabilities were measured in a clean silica sand core at an elevated temperature (100°C). A high viscosity (405 mPa.s at 23°C) refined mineral oil was used to simulate heavy oil behaviour. The other two fluids were nitrogen gas and de-ionized water.

LITERATURE REVIEW

The relative permeability of a fluid phase flowing horizontally through a porous medium in presence of other fluids is defined by the following equation:

$$\frac{Q_i}{A} = \frac{k_{ri}\ k_{abs}}{\Delta P_i\ L}\ (\mu_i\ P_i) \qquad (1)$$

where:

Q_i = Flow rate of fluid phase i,

A = Cross sectional area of the porous medium,

k_{abs} = Absolute permeability of the medium,

μ_i = Viscosity of fluid phase i,

L = Length of the porous medium,

ΔP_i = Pressure drop in the fluid i across length L,

k_{ri} = Relative permeability of fluid phase i.

This equation was originally proposed by direct analogy to flow of a single fluid through porous media. When only one fluid is present, k_{ri} becomes equal to one and the equation becomes the famous Darcy's law for single-phase flow. When two or more immiscible fluids are present, each fluid can occupy only a fraction of the total flow channels present in the system. It is therefore obvious that the effective permeability of the porous medium to any given fluid in presence of other miscible fluids will be less than the absolute permeability. Therefore, the term k_{ri} in the above equation would be less than or equal to one. It is also self evident that when more of this fluid is present in the medium it will occupy more of the available channels and hence its effective permeability will be higher. Therefore, the relative permeability term is expected to increase with increasing fraction of the total pores space occupied by this fluid. The fraction of total pore volume occupied by a given fluid is called the saturation of that fluid. Therefore, the relative permeability of a given fluid is a monotone increasing function of the saturation of that fluid.

Since a porous medium in general will have flow channels of many different sizes,

the relative permeability of a given fluid will depend not only on what fraction of the available pore space it occupies but also on what types of flow channels it occupies. If the fluid occupies smaller channels, its relative permeability will be smaller. Since more than one fluid may be present in a given flow channel, the flow of one will be impeded by the presence of the other fluid. Therefore, the sum of the relative permeabilities of all fluids present in the porous medium would be less than unity.

Thus it is evident that the relative permeability of a fluid in a given porous medium is determined by its distribution within the pore space. This distribution depends on several factors including the relative amounts of each fluid present, the past history of the system (i.e. how the fluids were introduced into the system), and balance of various forces acting on the fluids. Under static condition, these forces include the gravitational or buoyancy forces resulting from the density differences and the capillary forces arising due to the interfacial tensions or surface energies of the fluids. When fluids are in motion, the viscous drag forces and inertial effects may also play a role in determining the fluid distribution within a porous medium. Therefore the factors which can affect relative permeability of a given fluid include the following:

1. Pore geometry and pore size distribution of the medium.
2. Wetting preference of the solid in relation to other fluids present in the porous medium.
3. Saturation of the fluid.
4. Saturation history of the porous medium.
5. Densities of different fluids present.
6. Viscosities of different fluids present.
7. Interfacial tensions between different fluid pairs.
8. Velocity of various fluids.

When three fluids are present in a given porous medium, we have to consider three interfacial tensions, two viscosity ratios, two density differences, two saturations, three fluid velocities and the relative wetting preference of the solid for three fluids. Because of the complex geometry of the internal surfaces of natural porous media and the large number of

factors involved, it is generally not feasible to predict the relative permeabilities for a given fluids-rock system. It is therefore necessary to use experimentally measured values obtained in representative rock samples for reservoir engineering purposes. As will be shown later, even experimental measurements of three-phase relative permeabilities are subject to a variety of uncertainties.

The experimental research on three-phase relative permeabilities was initiated nearly half a century ago. First measurements were reported by Leverett and Lewis(1941). Since then several new experimental measurements and correlations have been reported. Collectively, these represent a considerable expenditure of effort towards the goal of developing an improved understanding of this complex process. Unfortunately, the results of various studies are generally not in complete agreement and it is not obvious which studies should be considered more reliable. It is therefore important to critically review these studies and identify their strengths and weaknesses. The objective of the review that follows is to see whether or not the disagreements between various studies can be explained on basis of differences in the systems used or experimental artifacts.

REVIEW OF PREVIOUS EXPERIMENTAL STUDIES:

Leverett and Lewis (1941):

The first ever paper on systematic experimental investigation of three-phase flow through a porous medium was authored by Leverett and Lewis (1941). They measured three-phase relative permeabilities in an unconsolidated sand pack using the steady-state technique. Water saturation was measured by the electrical resistivity technique while the gas saturation was measured by allowing the gas to expand to atmospheric pressure. Oil saturation was not measured directly but inferred from the other two saturations. The end effects were assumed to be negligible because of the relatively high pressure gradients used in the experiments (80 to 328 mm Hg). The reported independence of electrical resistivity at a fixed water saturation to the presence of a third phase shows that their system was strongly water-wet.

The authors considered dead space (space not filled with sand) in the cell to be the largest source of error (up to 6% in saturation measurements) followed by the errors due to incomplete attainment of steady-state. It is likely that the error in measurements of resistivity based water saturation was less serious. The measurements of oil and gas saturation would be affected more by the void space in the apparatus. It is likely that when all possible sources of errors are added, their gas saturation measurements could be in error by $\pm 10\%$. The oil saturation measurement was the least reliable of the three saturations since it contained errors of both the water and gas saturations.

The conclusions reached by these authors were that the water relative permeability was a function of its own saturation only and that the gas and oil relative permeabilities varied with saturations of all fluids. The gas isoperms presented by them show only a moderate degree of curvature. In view of the possible errors in gas saturation measurements and the scatter in the experimental data, a good case can be made for representing the same data by straight line isoperms. The oil isoperm lines show more pronounced curvature. Therefore, within experimental error, the results reported in this paper are consistent with strongly water-wet behaviour, i.e. the relative permeabilities of water and gas are depend on their own saturations while the oil relative permeability varies with all three saturations. An important conclusion reported in this paper was that the oil relative permeability did not change with oil viscosity. This was based on the results obtained with two oils differing in viscosity by an order of magnitude.

Caudle, Slobod and Brownscombe (1951):

The three-phase relative permeabilities reported in this paper were measured in a consolidated sandstone using a three piece core assembly with saturations and pressure drop measured on the central piece only. Saturations were obtained by weighing and vacuum distillation of the test core after reaching steady-state. The authors described the reported results as preliminary and conceded that not enough three-phase data were gathered to permit a complete description of the behaviour. It is not clear how the problem of saturation change due to gas expansion was solved prior to weighing or vacuum distillation of the test core.

Their results show that the relative permeabilities of all three phases vary with all three saturations. The degree of curvature was smallest in gas isoperms and largest in oil isoperms. The curvature in isoperm lines increased with decreasing saturation of each fluid. It is difficult to assess the magnitude of errors involved in these measurements because enough details of the procedure have not been reported. The possible sources of errors include the capillary end effects (only a short plug was used for measurements), changes in saturation during removal of the core from the core holder for weighing and vacuum distillation. It is likely that the measurement errors in this work were of the same magnitude as in the previous paper which will suggest that the curvatures in water and gas isoperms is within the range of experimental errors. In view of the preliminary nature of the reported results, this set of data can not be considered reliable for testing the accuracy of prediction techniques.

Corey, Rathjens, Henderson and Wyllie (1956):

Corey et.al. measured oil-water-gas three-phase relative permeabilities in water-wet Berea sandstone cores using $CaCl_2$ brine as the wetting phase. Nine different cores were used in the study and the results obtained on most of those were combined to asses the overall relative permeability behaviour. Capillary barriers were used to maintain constant water saturation while the saturations of oil and gas was varied. Thus the water relative permeability was not measured under three-phase flow conditions. The water isoperms presented in this paper were drawn by assuming that the water relative permeability in three-phase flow is function of its own saturation only and is therefore same as in two-phase flow. The saturation history represented by these measurements is in the direction of decreasing oil saturation with gas saturation increasing and water saturation being held constant. It is not clear in which direction the water saturation was changing before being held constant by the capillary barriers. The gas isoperms reported in this study were parallel to constant gas saturation lines showing that the gas relative permeability was a function of gas saturation alone. The oil relative permeabilities were found to vary with both oil and water saturations, the isoperm lines showing being concave towards the oil apex. The oil relative permeability

at a given oil saturation was found to increase with increasing water saturation.

The measurement technique used in this work is somewhat artificial in the sense that one of the fluids is held stationery even though its saturation is high enough to make it mobile. The use of several different cores, even though they were similar in properties, can be blamed for some of the scatter in the data. Since water was not allowed to move, the applied pressure gradient in the oil and gas phases must have resulted in changing water saturation to maintain the same hydrostatic pressure in the water phase at both ends. It is difficult to assess the contribution of this effect towards the observed relative permeability behaviour since flow rate information was not reported. Therefore the oil relative permeability data from this study may be unreliable for applications involving simultaneous flow of all three phases. The most significant conclusion derived from this work concerned the gas relative permeability behaviour. It was found that the gas relative permeability in this strongly water wet system was same function of gas saturation irrespective of whether or not water was present in the system. It was also noted that the oil permeability in two-phase oil/water system was similar to gas permeability in two-phase gas/oil system.

Reid (1956):

Reid conducted three-phase relative permeability measurements in high permeability (31 darcy) sand packs using the single core steady-state technique. Saturation and pressure drop measurements were obtained away from the inlet and outlet ends to overcome the capillary end effects. Water saturation was obtained by resistivity measurements and the gas saturation was measured by gamma ray attenuation technique. Hysteresis effects were ignored. The gamma ray technique for gas saturation measurements was based on the assumption that oil and water were equal in gamma ray attenuation properties. Electrical conductivity measurements were also found to be troublesome due to electrode corrosion. It is therefore probable that these measurements were no more accurate than the previous studies. His results show that relative permeabilities of all three phases vary with saturations of all three fluids. In addition his results showed that the oil relative permeability in the high oil saturation range at a given oil saturation was somewhat higher when both gas and oil

were present compared to the two phase situation. At low oil saturations the oil relative permeability appeared to increase with increasing water saturation. The water and gas isoperms were concave towards their own apexes. The deviations of isoperm lines for gas and water from the lines of constant saturation were within ±5% PV range. Therefore a ±5% error in saturation measurement would be sufficient to make the observed curvature insignificant. It is likely that the experimental errors in this work were of this magnitude.

Snell (1962):

In an attempt to improve the accuracy of saturation measurements, Snell employed a complex radio frequency RCL circuit for the water saturation measurements and a neutron bombardment method for the gas saturation measurement. Three-phase relative permeability measurements were carried out in a 120 cm long unconsolidated sand core of 7.1 darcy permeability. Ten equally spaced pressure taps were used for monitoring pressure drops in different sections of the core and the relative permeabilities were calculated from measurements of saturation and pressure drop over one or two segments of the core displaying uniform water saturation. Snell estimated the possible saturation errors to be ±2%. His results show that relative permeabilities of all three phases were functions of saturations of all fluids. However, the curvatures in gas and water isoperm lines were much smaller compared to that in the oil isoperms. Water isoperms were found to be concave towards the 100% water apex. These isoperms show that water relative permeability at a fixed water saturation increases as one moves away form the oil/water axis i.e. as some of the oil is replaced with gas. His gas isoperm lines are convex towards 100% gas apex and show an increase in gas relative permeability as one moves away from the gas/water axis, i.e. some water is replaced with oil and the oil becomes a mobile phase. Oil isoperms were also found to be convex towards the 100% oil apex. Oil relative permeability was lowest when both water and gas were present in roughly equal amounts.

He expressed some concern about the possibility of wettability alteration due to the presence of polar components in the oil phase. This concern was reinforced by presence of significant hysteresis in oil relative permeabilities showing lower oil relative permeability

when both oil and water saturations were decreasing. Oil relative permeabilities for all other liquid saturation histories appeared to fit same isoperms within the accuracy of these measurements.

The saturation measurement techniques used in this paper should have provided reasonably accurate data. A large number of measurements were carried out on the same core. It is likely that the core properties such as absolute permeability and wettability could have changed during the course of this investigation. Apparently the absolute permeability was measured only at beginning of the flow tests. In view of these uncertainties, these measurements are also somewhat unreliable.

Sarem (1966):

Sarem proposed an unsteady-state method for measuring three-phase relative permeabilities based on an extension of Welge's method. Unfortunately, the equations used for calculating relative permeabilities were developed on basis of the assumption that relative permeability for all phases are functions of the corresponding individual phase saturations only. This foreordains the isoperms to be straight lines parallel to lines of constant saturation. It is interesting to note that when tests in Berea sandstone were repeated with different starting water saturations, both water and oil relative permeabilities changed significantly while the gas relative permeability was not significantly affected. Since the method proposed by Sarem is based on a questionable assumption, the data reported by them can not be considered useful for testing prediction techniques.

Donaldson and Dean (1966):

Three-phase relative permeabilities in this investigation also were measured by an unsteady-state technique involving displacement of water and oil by gas injection. Berea sandstone and Arbuckle limestone were used as the porous media. An extension of Welge's formulation was used for calculating relative permeabilities without making the assumption that relative permeability to each phase is function of its own saturation only. Unfortunately details of the calculation scheme were not included in the report. It is therefore not possible

to comment on the validity of assumptions involved in calculations. Hysteresis effects were ignored and capillary effects were assumed to be negligible due to high gas injection rates used. Relative permeabilities calculated from different starting saturations of oil and water were combined to develop the overall picture.

Unlike Sarem the relative permeabilities in this study were found to functions of all saturations for all fluids. There are two reasons for questioning the reliability of the three-phase relative permeabilities reported in this paper. The calculation scheme used was not discussed fully and may have involved unsubstantiated assumptions. Secondly, in a displacement situation of the type used in these experiments, different parts of the core can experience different saturation histories. For example, if the gas mobilizes more oil than water, in parts of the core oil saturation will be increasing due to formation of an oil bank while in other parts the oil saturation will be decreasing. This would make it difficult to avoid hysteresis effects. Apparently the hysteresis effects were ignored. Sarem (1965) found that the starting saturation had a strong influence on oil and water relative permeability curves determined from similar experiments. Therefore, some of the curvature in the relative permeability curves presented by Donaldson and Dean could have resulted from a similar effect of different starting saturations.

Saraf and Fatt (1967):

Nuclear magnetic resonance was used for saturation measurements in this study. The experiments were conducted in strongly water wet Boise sandstone cores and hysteresis effects were avoided by using a fresh core for each set of steady-state tests. Pressure drop and saturations were measured away from the ends to minimize end effects. The tests were run in such a way that the saturation of water was held constant by maintaining constant water injection rate and constant differential pressure. Oil and gas saturations were varied and the NMR measurement was used to measure oil saturation. Water saturation was determined by material balance ($1 - S_o$) prior to gas injection and the gas saturation was determined by assuming that the water saturation did not change. They estimated that the

errors in water and gas saturation measurements were of the order of $\pm 2\%$. Their results show that water and gas relative permeabilities were functions of their own respective saturations only while the oil permeability varied with all saturations. The oil isoperm lines were slightly convex towards the 100% oil apex. These isoperms suggest that as one moves away from the oil-water axis along a constant oil saturation line, i.e. as water is replaced with gas, the oil relative permeability decreases at first and reaches a minimum and then shows a small increase. This increase is more pronounced at low oil saturations. The initial decrease is expected in water wet systems since decreasing water saturation will force the oil to occupy smaller pores but the reasons for the increase at higher saturations are less obvious. It is possible that as the water saturation becomes very low, some of the oil which was trapped as discontinuous blobs by surrounding water changes its character from the non-wetting phase to wetting phase and becomes mobilized. However the curvature in Saraf's oil isoperms is not very large and this increase in oil relative permeability with increasing gas saturation is within experimental error in saturation measurements.

The experimental techniques used in this work appear to be quite reliable and with the recent improvements in NMR technology (Edelstein et. al.; 1988) similar methods can be expected to provide even better accuracy in saturation measurements. A large part of the data scatter in this study stems from use of a different core in each set of measurements. The conclusion that relative permeability to water in the system investigated was function of water saturation only was proven independently, and can be accepted without qualification. The conclusion regarding dependence of gas relative permeability on gas saturation alone was based on lack of any consistent pattern in data showing large scatter. This conclusion is therefore less reliable. The curvature in oil isoperms reported in this paper is small and is based on combining results obtained in different cores. Therefore, the direction of curvature in oil relative permeability can also be considered less reliable.

Saraf et. al. (1982):

In this study the three-phase relative permeabilities were measured in Berea sandstone using both the steady-state single core technique as well as an unsteady-state technique based on Sarem's work. In this work the calculations of relative permeabilities from unsteady-state displacement data were based on assumptions similar to those in Sarem's paper but with one difference. The assumption that oil permeability is a function of oil saturation alone was applied only over a small saturation range. This will be equivalent to replacing the oil isoperms with a collection of small straight line segments parallel to constant oil saturation lines. The relative permeabilities calculated from this procedure were found to be similar to steady-state values. Oil and water were circulated in closed loops containing a windowed cell and the saturations were measured by material balance.

The results of this study again showed that in strongly water wet systems the water relative permeability is a function of water saturation only. The gas relative permeability was found to be a function of gas saturation only as long as the direction of S_g variation remained same. Significant hysteresis effect was found in gas relative permeability. The oil relative permeability was found to be a function of both oil and gas saturations and it was also affected by the direction of gas saturation change. The curvature in oil isoperm lines was predominantly concave towards 100% oil apex, although at low oil saturations some of the lines showed a point of inflection.

The steady-state results obtained in this study appear to be quite reliable. There is some question as to the validity of the unsteady-state technique employed. The reported oil isoperms are based on combination of both type of measurements and therefore may have suffered from the assumptions involved in the unsteady-state technique.

Oak et. al. (1988):

In this study oil-water-gas three-phase relative permeabilities were measured by the steady-state technique using the Penn State method for overcoming the capillary end effects. Tests were conducted in fired Berea sandstone cores. Dual energy X-rays were used to measure all three saturations. X-ray absorbing tracers were dissolved in the liquids to enhance measurement accuracy. Two types of saturation histories were investigated. In the first set of experiments both oil and water saturations were decreasing and gas saturation was increasing. In the second type of saturation history gas saturation was decreasing while oil and water saturations were increasing. The core was cleaned after each displacement sequence and its absolute permeability was measured periodically and was found to decrease continuously during the year long experimentation.

The results of this investigation are similar to those reported by Saraf et. al. (1982). Water relative permeability was found to be a function of water saturation only. Gas isoperms show some deviations from straight lines for one saturation history while for the other saturation history the gas permeability appears to be a function of gas saturation only. Oil isoperms show more complex behaviour including some points of inflection. The experimental data was compared with Stone's prediction models. The predicted values were significantly different from measured values.

Even though very sophisticated experimental techniques were used in this study the results still show scatter in the data. The number of measurements reported is relatively low and the authors did not attempt to draw smooth oil isoperms on basis of the experimental data.

CONCLUDING REMARKS ON THE REVIEW OF PREVIOUS STUDIES:

Taken together the experimental studies reviewed in the foregoing show that three-phase relative permeability saturation relationships are very difficult to measure with high precision. The reported isoperms are usually drawn by filtering out the scatter from

experimental data. This often requires making subjective judgment in resolving conflicts between data points which do not agree.

The accuracy of reported results has undoubtedly improved with improvements in technology over the period spanning half a century. The number of reported experimental studies is relatively small and a good case can be made for continuing this type of work in different systems. However, the measurement techniques remain tedious and not well suited for making measurements in reservoir cores under reservoir conditions. The effort required in completely characterizing relative permeability behaviour of a single core is so great that measuring three-phase relative permeabilities on a routine basis is not practical. Therefore reservoir simulation studies will have to rely on prediction techniques for some time to come. The immediate objective of research in this area should be to improve the reliability of prediction techniques. Unfortunately, this can not be achieved until many more three-phase relative permeability measurements in different types of system become available.

DEVELOPMENT OF AN IMPROVED EXPERIMENTAL APPARATUS FOR STEADY-STATE THREE-PHASE RELATIVE PERMEABILITY MEASUREMENTS

The steady-state method of measuring three-phase relative permeability requires establishing steady flow of three fluids through the porous medium and measuring the pressure drop and flow rate for each fluid. The relative permeability for each fluid can then be calculated directly by applying the Darcy's law (eq. 1). The additional information needed to calculate the relative permeability of each fluid includes: the absolute permeability of the medium; viscosity of the fluid; cross sectional area of the medium; and the length of the porous medium, all of which can be measured separately. Since the objective of relative permeability measurements, usually, is to determine the relationship between relative permeability and saturation, it is also necessary to measure the saturation of each fluid under steady-state conditions. Different saturation conditions are obtained by varying the flow rates of the three fluid phases in a systematic manner. When sufficient data have been collected the saturation versus relative permeability relationships can be defined.

An experimental equipment, capable of operating at elevated temperatures, was developed in this laboratory and used for steady-state three-phase relative permeability measurements reported previously (Maini et. al., 1989). Figure 1 shows a schematic diagram of this equipment. During the course of that study, it became apparent that the reliability of such measurements was affected by two factors. Even though the contribution of capillary end effects was reduced by using high flow rates and a long core, it was still a problem. Secondly, some water was lost from the system with the gas stream being purged out of the system. This occurred despite full humidification of the gas stream before entering the core. The reason was related to the small expansion of the gas phase in passing through the core. This water loss reduced the reliability of the material balance based saturation measurements. Furthermore, it was felt that a micro-computer based data acquisition system would be helpful in reducing the tedium of such measurements. Therefore a major upgrade of the equipment was undertaken with the following objectives:

1. Minimize the capillary end effects by modifying the core holder.
2. Improve the reliability of saturation measurements by installing an in-situ water saturation measurement technique.
3. Improve the reliability of data collection by installing an on line data acquisition computer.

MINIMIZATION OF CAPILLARY END EFFECTS

At the outflow boundary of the core, the nature of the flow changes abruptly from flow in porous medium to bulk flow in tubing. This change is accompanied by an abrupt change in the curvature of fluid-fluid interfaces. These interfaces are highly curved inside the porous medium due to the small dimensions of flow channels in the porous medium but become relatively flat immediately after coming out of the core. Therefore, the pressure in two adjacent fluids can be quite different within the porous medium but is nearly equal on the outside boundary. Since, pressure discontinuities can not exist within the flowing fluid phase, the simultaneous flow of different phases out of the core face is possible only when the pressure within each pase is same on both sides of the outflow boundary. For the fluid having a higher pressure within the porous medium, i.e. the non-wetting fluid this presents no problem since its pressure would be the same on both sides of the outflow boundary. The fluid which has lower pressure within the porous medium, i.e. the wetting fluid may face an increase in pressure in going from the porous medium side of the boundary to the other side. Therefore it can not flow out until its pressure at the inside boundary becomes equal to that of the non-wetting fluid. This can only happen when its saturation becomes equal to that corresponding to the zero capillary pressure on the capillary pressure versus saturation diagram. Therefore, the wetting phase saturation must build up near the inside boundary of the porous medium. This build up of wetting phase saturation can cause serious error in relative permeability measurement if core average saturations and pressure drops are used for relative permeability calculations. Several ways of minimizing or overcoming this problem have been reported in the literature. The following presents a brief review of the

more useful among these:

Capillary Pressure (Hassler) Method:

This method was developed by Hassler (1944) for two-phase relative permeability measurements but can be adopted to three-phase measurements also. It is based on the idea that the end effects will not arise if the fluids do not have to come out of the porous medium simultaneously from same location. To ensure this condition, semi-permeable membranes are provided at each end to produce different fluids from different outlets. Pressure is measured separately in different fluids and the pressure difference between phases at the outflow end can be adjusted by controlling the back pressure for each fluid separately. Therefore, the capillary pressure can be kept same at inlet and outlet ends which ensures uniform saturation along the core. Using this technique for three-phase measurements will require three different semi-permeable membranes each permeable to one fluid only. If only two membranes, one permeable to water and the other permeable to oil and gas, are used the end effects would be reduced but not completely eliminated. The method is quite cumbersome and is currently not very popular. Finding suitable membranes for three-phase measurements and maintaining their semi-permeable character over extended periods can also present some problems.

Dynamic (Penn-State) Method:

This method was initially developed by Morse et. al.(1947) for two-phase relative permeability measurements. They placed three pieces of similar core material in series in a core holder, with the idea that the front piece will serve as the inlet section and the last piece will absorb the capillary end effects. Measurements of saturation and pressure drop were made on the central piece only which was the core to be tested. This method should work reasonably well in a three-phase system also, provided a perfect capillary contact can be ensured between the adjoining cores. This method of minimizing end effects makes the saturation measurement somewhat more difficult. Unless in-situ techniques are used, the saturation measurement requires removing the test core from the holder for each

measurement. Recent reports indicate that the capillary contact may not be perfect even when materials like tissue paper are placed between the adjoining cores. In addition, there is no guarantee that the end effects will be confined to the last piece of the core only. If very slow flow rates are used the end effects may propagate to the test section also.

Use of High Flow Rates:

Perhaps the simplest technique for minimizing end effects is to use high flow rates. As the flow rate is increased the region over which wetting phase saturation accumulates shrinks in size and at high flow rates may be confined to a narrow section near the outflow face of the core (Geffen et. al., 1951; Josendal et. al., 1952). If the pressure drop and saturations are measured away from the core, the end effects' problem can be solved. The advantage of this method over the Penn-State method is that there is no uncertainty about the capillary contact. However, in some cores the use of high flow rates may cause fines migration problems.

Use of Long Cores:

The problem of end effects can also be solved by using a long core and obtaining measurements away from ends. If unconsolidated sand is being used it is possible to attach a long but narrow extension (in a small diameter tube) to the main core without interrupting the continuity of the sand. In this situation the end effects will probably remain confined to this tube and the measurements can be obtained in the main body of the core.

Richardson and Perkins (1957) Method:

This method relies on attachment of a narrow packed tube to the outflow end of the core. The packed tube must be in capillary contact with the main core section. Because of the very high flow rate and high pressure gradient in the narrow section, the end effects remain confined to the narrow tube section. This method is particularly suitable for unconsolidated sand packs since the capillary contact between the wide core section and the narrow tube section can be easily assured.

Method used in this study:

The technique used in this work was a combination of the Richardson and Perkin's narrow tube attachment, high flow rates and long core. The final design of the core holder is shown in Figure 2. The cross sectional area of the narrow tube section was more than two orders of magnitude smaller than the main core. Thus the flow rates were more than two orders of magnitude higher in this section. The length of the narrow section was 15 cm while the length of the main core section was 45 cm. A short length narrow section was used to minimize the effect of saturation variation in this section on the core average saturation measurements by material balance. The pore volume contained in this section was less than 0.2% of the pore volume in the main core section. Therefore, the effect of any saturation variation in the narrow section on core average saturation could be neglected.

The pressure drop was measured 2.5 cm away from the ends of the main core section. We believe that this combination of a long core, a narrow end effect absorbing section and use of relatively high flow rates should provide adequate protection against the capillary end effects.

IN-SITU WATER SATURATION MEASUREMENT:

As mentioned earlier, the loss of some water with the out flowing gas stream made the material balance based saturation measurements less reliable in the original version of the equipment. To overcome this problem, it was necessary to either find an alternate way of saturation determination or eliminate the problem of water loss. The only sure way of preventing the water loss appeared to be to find some means of re-circulating the gas phase and thus eliminating the out going gas stream. While it is possible to design a gas re-circulation system based on re-compressing the gas and using an appropriate flow controller, it introduces another complication. Some water is likely to drop out of the gas as a result of the re-compression. Since such re-compression unit will have to be located outside the oven, the unavoidable cooling of the gas stream will also cause water condensation problems.

Therefore it was decided that the re-circulation of gas would be problematic and it would be preferable to find an alternate saturation measurement method.

It was noticed in the previous work that the material balance was much more accurate for the oil phase and the oil saturation measurements were generally accurate. Therefore, it would be necessary only to find an alternate method of measuring the water saturation. An in-situ technique based on electrical resistivity measurement appeared to be attractive because of its simplicity and relatively low cost. The alternates of micro-wave or X-ray attenuation methods were ruled out due to the large capital expense required and difficulties in using those techniques at high temperature. Therefore, the electrical resistivity measurement was selected as the technique for in-situ water saturation determination.

Figure 3 shows the placement of electrodes within the core holder. A monel screen, placed perpendicular to the core axis near the centre of the core was used as one of the electrodes. The body of the core holder served as the other electrode. A teflon inner sleeve was place between the sand and the lead sleeve to electrically isolate the sand. Thus the electrical current had to flow between the monel screen and the end plates of the core holder through the sand. The resistivity measurement was carried out at 1000 hz. To eliminate the effect of brine composition the resistivity of the core was compared with the resistivity of another sand pack place in the brine recirculation system. This second sand pack remained fully saturated with brine at all times and since it was a part of the brine re-circulation path, it contained the same brine as flowing through the core.

A calibration curve, relating the electrical resistivity index of the core to its water saturation was established by carrying out two phase oil/water and gas water tests. The resistivity index was measured directly by measuring the ratio of electrical resistance of the core and the resistance of the fully brine saturated secondary cell. The water saturation in the oil/water tests was determined by material balance. In case of water/gas tests the water saturation was determined by measuring the volume of additional water needed to completely re-saturate the core following a blow down to the atmospheric pressure. The final calibration curve is shown in Figure 4.

ON-LINE DATA ACQUISITION SYSTEM:

An on-line data acquisition computer was installed for recording the pressure drop and resistivity data directly magnetic disks. An IBM PC-XT computer equipped with Metrabyte Dash-16 data acquisition board was used for this purpose. A data acquisition program was written to record pressure transducer readings and the values of the a.c. voltages across the resistivity probes.

Figure 5 shows a schematic diagram of the modified apparatus. The parts within the dotted enclosure were contained in a convection oven equipped with a temperature controller capable of maintaining constant temperature within 0.5°C. Both water and oil were circulated in closed loops. The loop for water included the separator cell, a dual piston HPLC pump (Beckman Model 100 A), the reference resistivity cell, a heat exchanger coil, a capillary viscometer, and the test core. The water flow started from bottom of the separator cell and passed successively through the circulation pump, the heat exchanger tube, the reference resistivity cell, the water viscometer and the core before returning to the separator cell. Thus any change in the volume of water contained in the core was accompanied by an equal but opposite change in the volume of water in the separation cell. Similarly the oil started from middle of the separator cell and passed successively through the oil circulation pump (Beckman Model 100 A), heat exchanger tube, the oil viscometer and the test core before returning to the separator cell. Two syringe pumps, one containing water and the other containing oil, were connected to the separator cell as shown in Figure 5. These were used to maintain the required volumes of the liquids in the separator cell by injecting or withdrawing the fluids.

Gas flow was in once through mode. The gas was taken from a compressed gas cylinder, flowed through a mass flow controller, a fixed bed humidifier, a mist filter, a gas viscometer, the test core, the separator cell, a second mist filter, a back pressure regulator and a soap film gas flow meter.

The cores were wet packed and then confined by application of triaxial stress using a technique described elsewhere (Maini et. al. 1985).

At start of each run the core was solvent cleaned, dried with hot nitrogen, evacuated and then filled with metered volume of water to determine its pore volume. The water re-circulation loop was filled with water but the syringe pump for water and the separator cell were kept almost empty. The oil syringe pump was filled with oil and most of the separator cell also contained oil (except for a small volume of water at the bottom and a gas cap at the top). The system was then pressurized by injecting the gas. The absolute permeability of the core was measured by flowing water through the core. This also allowed the water to contact and become saturated with the gas. The oil was equilibrated with the gas by circulating it through the gas cap in the separator cell without going through the core. The levels of water and oil in the separator cell and the volumes contained in the syringe pumps were recorded after both fluids became saturated with the gas.

The next step was an oil flood to drive the core to its irreducible water saturation. The volume of water produced was monitored by reading the water level in separator cell and withdrawing water into the water syringe pump when needed. The oil flow was continued till water production from the core ceased and the pressure drop across the core became constant.

Simultaneous flow of water, gas and oil was then started with low flow rates of water and gas and relatively high oil flow rate. After reaching a steady-state condition (as indicated by constant pressure drop and constant fluid levels in the separator cell for at least 12 hours) the pressure drop across the core, the resistivity values and the liquid levels in the cell were recorded. Usually 24 hours were enough for each set of flow rates except at the flood out (zero oil flow) where three to five days were needed. The fractional flows of water and gas were increased and the oil flow rate was decreased in each successive flow rate settings. If the pressure drop across the core became too low, flow rates of all three fluids were doubled. Eight to ten different flow rate settings were used to reach the zero oil flow condition. After reaching the residual oil condition the core was isolated and depressurized. The liquids produced with the gas during this depressurization were collected in a cold trap. The core was then extracted by flowing hot toluene through it. The liquids produced from the core were collected and distilled to determine water and oil saturations

existing in the core at end of the test. The core was then ready for the next run.

Relative permeability to each phase was calculated by applying Darcy's law. Even though the pressure gradient was measured away from the core ends, the saturations were the core average. This introduces an additional error in the saturation measurement, however, since the core length was more than 45 cm this error is likely to be small. The maximum error in saturation measurements was estimated to be about $\pm 2.5\%$. The average error in core average saturation measurement would be considerably less than this value. The fractional error in pressure drop measurements varied with the value of pressure being measured. The readability of pressure drop measurement was of the order of 0.35 kPa. This represented about 6.5 % of the lowest pressure drop reading used in the tests. This combine with the calibration errors in the transducer could have resulted in a maximum of $\pm 15\%$ error in the pressure measurements.

MEASUREMENTS OF THREE-PHASE RELATIVE PERMEABILITIES

The relevant petrophysical properties of the core and fluids used in this study are listed in Table 1. The measurements listed in the table were carried out at 100°C at the start of the experimental program. The same core was used for all experiments. Some gradual changes in core properties occurred during the course of this study. The absolute permeability declined gradually and was down to be 3.0 darcy by the end. The pore volume did not change significantly. Fresh fluids were used for each run and there was no measurable change in fluid properties during the runs.

Before starting the three-phase measurements, two-phase oil/water and oil/gas relative permeabilities were measured by the steady-state technique. The two-phase oil/water relative permeabilities in imbibition direction are shown in Figure 6. The lines drawn through experimentally measured points were obtained by fitting the following equation to the data:

$$k_{ro} = k^{o}_{ro} \frac{(1-S)^{\epsilon_{o,ow}} + 0.01(1-S)}{1.01} \qquad (2)$$

and

$$k_{rw} = k^{o}_{rw} \frac{S^{\epsilon_w} + 0.01S}{1.01} \qquad (3)$$

where $S = (S_w - S_{wi})/(S_{wm} - S_{wi})$, S_{wi} and S_{wm} being the irreducible and maximum water saturations and k^{o}_{ro} and k^{o}_{rw} are the end point relative permeabilities to oil and water. The water relative permeability curve is typical of water-wet systems. However, the oil curve shows very little curvature. Furthermore, it is concave downward. Although, this type of behaviour is not very common, similar results have been reported previously for viscous oil

systems. The oil/water drainage relative permeabilities are shown in Figure 7. The smooth curves again represent least square fits of the above equations. The drainage relative permeability curve for oil also shows a small curvature but is concave upward. The hysteresis in oil/water relative permeability is shown in Figure 8. A small amount of hysteresis was is seen in the water relative permeability. This, however, is within the range of experimental error and not considered significant. The oil curve shows more pronounced hysteresis.

Figure 9 shows the two-phase oil/gas relative permeabilities in the direction of decreasing oil saturations. These measurements were carried out at an irreducible water saturation of eight percent. Since the starting gas saturation was zero, the end point oil relative permeability was same as in the oil/water case. The smooth curves shown in this and other oil/gas relative permeability figures were obtained by fitting the following equations:

$$k_{ro} = k^{o}_{ro} \frac{(1-S)^{\epsilon_{o,og}} + 0.01(1-S)}{1.01} \tag{4}$$

and

$$k_{rg} = k^{o}_{rg} \frac{S^{\epsilon_g} + 0.01S}{1.01} \tag{5}$$

where $S = (S_g - S_{g,min})/(S_{g,max} - S_{g,min})$, $S_{g,min}$ and $S_{g,max}$ being the minimum and maximum gas saturations and k^{o}_{ro} and k^{o}_{rw} are the end point relative permeabilities to oil and gas. Figure 10 shows a comparison of oil/water and oil/gas relative permeability curves, both sets being in the direction of decreasing oil saturations. As expected, at similar saturations the gas relative permeability is much higher than water relative permeability and the oil relative permeability is lower in oil/gas case.

Oil/gas relative permeabilities in the direction of increasing oil saturations are shown in Figure 11. Surprisingly, there appeared to be little or no hysteresis in oil/gas relative

permeabilities. This can be seen clearly in Figure 12 where both sets of experimental points are plotted with the fitted curves representing relative permeabilities in the direction of decreasing oil saturations.

THREE-PHASE WATER RELATIVE PERMEABILITY:

Three-phase water relative permeability was measured both in imbibition and drainage directions. The imbibition water relative permeability is plotted against water saturation in Figure 13. A total of seven steady-state three-phase runs are represented in this figure. Also shown are the two-phase results presented previously. Although considerable scatter in the data points is evident, no specific trend could be detected with the saturations of the other phases. Therefore, only a single curve can be justified to represent this data.

Figure 14 shows the three-phase relative permeability in drainage direction. Again, considerable scatter is evident but no clear trends could be established with the saturations of the other phases. A comparison with Figure 13 shows that the behaviour is similar to the imbibition case. In Figure 15 both imbibition and drainage data are plotted together. It is apparent from this figure that any difference between imbibition and drainage water relative permeability, if present, is smaller than the scatter in the data. For all practical purposes, the hysteresis in three-phase water relative permeability of this system can be considered insignificant.

THREE-PHASE GAS RELATIVE PERMEABILITY:

Three-phase gas relative permeability was also measured in two directions of saturation change. The first set of measurements involved increasing gas and saturations and decreasing oil saturations while the other set was in the opposite direction. Figure 16 shows the three-phase gas relative permeability behaviour in the direction of increasing gas saturations. The gas relative permeability also showed no clear trend with the values of oil and water saturations. Therefore only a single curve could be justified to represent the data. Furthermore, the two-phase points appear to merge well with the three-phase data.

Therefore, it was concluded that within the accuracy of the measurements the gas relative permeability is a function of its own saturation only.

Three-phase gas relative permeability in the direction of decreasing gas saturations are shown in Figure 17. The experimental points show considerable scatter. Again it was concluded that the gas relative permeability in this direction of saturation change is also a function of only its own saturation. Figure 18 shows the extent of hysteresis in gas relative permeability. It is evident that only a minor amount of hysteresis is present and also that it is more significant at low gas saturations. The lack of large hysteresis in gas relative permeability is surprising since one would expect the gas to be trapped by advancing oil and water. However, the steady-state trapped gas saturation was only about four percent in this system. This low trapped gas saturation is believed to be responsible for the lack of pronounce hysteresis in gas phase relative permeability.

THREE-PHASE OIL RELATIVE PERMEABILITY:

Figure 19 shows a plot of the oil relative permeability as a function of oil saturation for the case of decreasing oil saturations. The oil/water and oil gas data are included in the plot. It was observed that the three-phase oil relative permeability when plotted against oil saturation showed more scatter compared to the corresponding water and gas relative permeability plots. Also in general the oil relative permeabilities from runs involving low gas saturations were closer to the oil/water two-phase measurements and similarly the runs involving low water saturations showed results closer to the oil/gas measurements. Therefore, the three-phase oil relative permeability was replotted on a triangular graph in form of isoperms. Although there was considerable scatter, the shapes of isoperms could be easily defined. Smoothed oil isoperms, shown in Figure 20, show significant curvature. The line representing zero relative permeability shows that when both water and gas are used to displace the oil a significantly lower residual oil saturation results. Three-phase relative permeabilities in the direction of increasing oil saturations are shown in Figure 21. The

shape of the isoperms is similar to those obtained in the direction of decreasing oil saturations. Figure 22 plots the two sets of isoperms and shows that only a minor hysteresis is present in the three-phase oil relative permeability. The magnitude of hysteresis is actually of the same order as the accuracy of these measurements.

EVALUATION OF THREE-PHASE RELATIVE PERMEABILITY CORRELATIONS:

The correlations used most frequently in reservoir simulation studies in the absence of three-phase data are the two models of Stone designated as Method I and II. These methods use two sets of two-phase data to predict the three-phase relative permeabilities. This approach seems reasonable because three-phase oil-water-gas system is bounded by oil-water, oil-gas and water-gas flow on the three sides. Stone's Method I suggests the use of two sets of oil-water and oil-gas data to obtain the three-phase relative permeabilities. Hysteresis effects are taken into consideration by using the appropriate two-phase data. For systems with water as the wetting phase, oil as the intermediate wetting phase and gas as the non-wetting phase, Stone suggested that three phase gas and water relative permeabilities were dependent only on their own saturations and are equal to the two-phase values,

$$k_{rg} = f(S_g) \tag{6-a}$$

$$k_{RW} = f(S_w) \tag{6-b}$$

while the relative permeability to oil depends on the saturations of all three phases. For the oil phase, the relative permeability under three-phase flow conditions is obtained from:

$$K_{ro} = S_o^* \; b_w \; b_g \tag{7}$$

where:

$$b_w = \frac{k_{row}}{(1-S_w^*)} \tag{8-a}$$

$$b_g = \frac{k_{rog}}{(1-S_g^*)} \tag{8-b}$$

$$S_o^* = \frac{S_o - S_{om}}{1 - S_{wc} - S_{om}} \tag{9}$$

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{om}} \tag{10}$$

$$S_g^* = \frac{S_g}{1 - S_{wc} - S_{om}} \tag{11}$$

b_g and b_w are factors to allow for oil blockage by gas and water respectively. Equations (8-a) and (8-b) involve two-phase data only. One of the advantages of Stone's Method I is the parameter S_{om}, the minimum residual oil saturation, which can be adjusted to match the three-phase data. Stone suggested the use of S_{om} between $0.25S_{wc}$ to $0.5S_{wc}$ based on experimental data. S_{om} should be less that or equal to the lesser of S_{orw}, the residual oil saturation in oil-water flow and S_{org}, the residual oil saturation in oil-gas flow. Fayers and Matthews suggested the use of;

$$S_{om} = a\, S_{orw} + (1-a)\, S_{org} \tag{12}$$

where:

$$a = \frac{1 - S_{wc} - S_{org} - S_g}{1 - S_{wc} - S_{org}} \tag{13}$$

In the absence of any experimental data equation (12) should be used to obtain S_{om}.

Stone later suggested the following (method II) equation for obtaining the three-phase relative permeability to oil:

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) - (k_{rw} + k_{rg}) \tag{14}$$

where k_{row} and k_{rw} are the two-phase relative permeability to oil and water from two-phase oil-water data and k_{rog} and k_{rg} are the relative permeabilities to oil and gas from two-phase oil-gas data. Stone's Method I and II have only been partially successful as demonstrated by Dietrich and Bondor (1976), Saraf et al. (1982), van Spronsen (1982), Fayers and Matthews (1984) and Oak et al (1988). One of the problems associated with the Stone's models is the implicit assumption that k_{row} and k_{rog} are equal to unity at connate water saturation (oil-water) and zero gas saturation (oil-gas). This is not true in general and consequently the three-phase relative permeability predicted by Stone's model do not match the two-phase data at the oil-water and oil-gas boundaries. A few modifications have been made to the Stone's models by Dietrich and Bondor (1976), Aziz and Settari (1979), Fayers and Matthews (1984), Fayers (1987), Aleman et al. (1984). These modifications have only been partially successful. In a recent paper Baker reported that simple interpolation models (both linear and saturation weighted) provide as good or better match of experimental data than any of the previous models including those of Stone's.

MODIFICATIONS OF STONE METHOD I

One of the limitations of Stone's method arises from the fact that if k_{row} and k_{rog} are not equal to unity at connate water saturation (oil-water) and zero gas saturation (oil-gas),

then a match in relative permeabilities cannot be made at the two-phase boundaries. Aziz and Settari modified Stone's method I by assuming that the gas-oil data are measured in the presence of irreducible water. For this case, $k_r^o{}_{ow}$, the relative permeability of oil at connate water saturation in an oil-water system is equal to $k_r^o{}_{og}$, the relative permeability to oil at zero gas saturation in an oil gas system. They modified the Stone's method I as follows:

$$k_{ro} = k^o_{row}\, S_o\, b_w\, b_g \tag{15}$$

$$b_w = \frac{k_{row}}{k^o_{row}\,(1-S_w^*)} \tag{16}$$

$$b_g = \frac{k_{rog}}{k^o_{rog}\,(1-S_g^*)} \tag{17}$$

The effect of this modification is to normalize the relative permeability. The problems with Aziz and Settari's method are (a) some measurements of two-phase oil gas relative permeability data are not necessarily conducted at connate water saturation and (b) $k_r^o{}_{ow}$ is in general not equal to $k_r^o{}_{og}$ due to experimental error. To overcome this problem, Kokal and Maini (1990) further modified the Stone's model by incorporating another normalizing factor. The following expression for k_{ro} was found to work well for this purpose:

$$k_{ro} = S_o^* \left[\frac{k_{row}}{k^o_{row}(1-S_w^*)}\right]\left[\frac{k_{rog}}{k^o_{rog}(1-S_g^*)}\right]\left[\frac{k^o_{rog}S_g^* + k^o_{row}S_w^*}{1-S_o^*}\right] \tag{18}$$

where $k_r^o{}_{ow}$ and $k_r^o{}_{og}$ are the relative permeabilities to oil at connate water saturation (oil-water) and zero gas saturation (oil-gas) respectively. At connate water saturation during oil-water flow, equation (18) reduces to,

$$k_{ro} = k_{rog} \tag{19}$$

and at zero gas saturation during oil-gas flow equation (15) reduces to

$$k_{ro} = k_{row} \tag{20}$$

Equations (19) and (20) are the required equations for a two-phase match of relative permeabilities at the oil-gas and oil-water boundaries. The term,

$$\left[\frac{k^{o}_{rog}S^{*}_{g} + k^{o}_{row}S^{*}_{w}}{1-S^{*}_{o}}\right]$$

is a normalization factor which forces a match at the two-phase ends.

The new experimental data was used to evaluate the validity of the new correlation reported represented by Equation 18. Figure 23 compares the new experimental data with predicted values from this correlation. For most parts the correlation provides an excellent fit of the experimental data. As expected, the match between the predicted and experimental values is perfect at the oil-water and oil-gas boundaries.

DEVELOPMENT OF AN UNSTEADY-STATE TECHNIQUE FOR THREE-PHASE RELATIVE PERMEABILITY MEASUREMENTS

Because of the large time required for steady-state measurements, it is recognized that a more rapid alternate technique is needed before experimentally measured three-phase relative permeabilities can be used routinely. Consequently several attempts have been made in the past toward developing such a technique. Sarem (1966) was the first to propose a technique to estimate three-phase relative permeabilities from unsteady-state displacement data. His technique was essentially an extension of the Welge's analysis (Welge, 1952) and JBN method (Johnson el al., 1959) for the two-phase flow. Like the JBN method, this technique, too, neglected the effects of capillary pressures on the saturation distributions and did not take into account the end effects, i.e. the capillary discontinuity. Therefore, it is suggested that for this technique to be applicable, displacement experiments must be conducted at higher rates.

Donaldson and Dean (1966) also reported use of a similar unsteady-state method to estimate three-phase relative permeabilities. Although both these studies used the same type of sandstone, there were, however, few notable differences between these two studies. For example: (i) Sarem assumed relative permeability to each phase to be function of its own saturation only; while Donaldson and Dean demonstrated that relative permeabilities to each phase were function of all the three phases present in the system, (ii) Sarem neglected the end effects, while Donaldson and Dean minimized them by conducting displacement at very high flow rates. However, unlike Sarem, Donaldson and Dean presented neither the derivation nor the assumptions involved in their calculations thereby making a critical review of their work rather difficult.

In 1967, Saraf and Fatt demonstrated that Sarem's principal assumption -- that relative permeability to each phase was a function of its own saturation only -- was not a valid one. Using a nuclear magnetic resonance technique to monitor liquid saturations, and a volumetric method to estimate gas saturations in unsteady-state displacement runs, they reported that the

relative permeability to water was a function of its own saturation only and such was not the case for oil and gas phases. Relative permeability to oil was found to be a function of both oil and water saturations, while the relative permeability to gas was found to be a function of the total liquid saturation within the porous medium.

A later study by Saraf et al.(1982) demonstrated that oil relative permeabilities were dependent on saturations of all the phases in the porous medium. This study also investigated the effect of the direction of saturation change on relative permeabilities to each phase. Relative permeabilities to the water were found to be independent of saturation histories, and relative permeabilities to the gas were found to be strongly dependent on the direction of saturation change in the gas phase. Although the direction of oil and water saturation changes did not affect relative permeabilities to the oil significantly, the decreasing gas saturation resulted in higher values as compared to those with the increasing gas saturation.

It has been shown that the pressure and recovery data collected during a linear displacement test are sufficient to characterize the two-phase relative permeability characteristics of the system (Batycky et.al., 1981). An extension of this observation to displacements involving three phases suggests that such displacements may provide sufficient information to infer the three-phase relative permeability characteristics of the system. However, it is difficult to conclusively prove the validity of this premise without invoking simplifying assumptions. Since, for a given set of displacement conditions, fixing the three-phase relative permeability fixes the calculated pressure drop and recovery behaviour, it is likely that the experimentally observed displacement history can be used to infer relative permeabilities. Simple intuitive reasoning suggests that the information provided by such a measurement will be limited to saturations actually realized in the displacement. However, this limitation can be overcome by running several displacements at different conditions to expand the region of three-phase saturations physically occurring in the experiments. Although it remains to be proven, we proceed by assuming that the external measurements (i.e. pressure drop and flow rates at core boundaries) recorded during core displacements involving three-phase flow provide sufficient information to infer the three-phase relative

permeability characteristics of the system over the saturations and saturation histories physically realized during the displacements. The problem then reduces to developing a calculation procedure for inferring the relative permeability characteristics. The most general case of such a displacement would involve simultaneous injection of all three fluids into a core containing known saturations of all three fluids much as is done in the steady-state tests but with a much larger saturation change as the target. However, it may be more practical to displace one fluid by simultaneous injection of two fluids or alternatively displace two fluids with injection of one fluid.

CALCULATION METHOD:

The calculation method adopted in this study is essentially an extension of the unsteady-state method of Johnson et al. (1959) and Jones and Roszelle (1978) for estimating two-phase relative permeabilities to three-phase situation.

Three-phase relative permeabilities to oil, water and gas were calculated by using the equations proposed by Sarem (1965). Capillary effects were neglected and the saturation of each phase was obtained in terms of fractional flows of the displacing phases (gas and water).

Cumulative fluid-recovery history and pressure-drop data were smoothed by using two functional equations similar to those proposed by Sarma and Bentsen (1989), and then the differentiation of experimental data as required by Sarem's method is carried out. In fitting these data, simultaneous change in individual fluid saturations were taken into account. Because of the unsteady-state displacement process, only post-breakthrough data are considered in this analysis.

RELATIVE PERMEABILITY CURVES:

Three-phase oil relative permeabilities obtained from experimental data are plotted in Figures 24. The shape of the oil isoperms is similar to those obtained in the steady state tests. All oil isoperms are concave towards the oil apex and the oil relative permeability is definitely not a function of oil saturation alone. At first glance this may appear to be in

conflict with one of the assumptions involved in the calculation scheme. Although Sarem's equations are based on the assumption that the relative permeability of each phase is function of its own saturation, the final result shows relative permeabilities to vary with other saturations. This apparent conflict results from the way this assumption is used in the calculations. The isoperms shown in Figure 24 are derived from results of six displacement runs. Each run was analyzed separately and provided only one discrete point on any given isoperm. Although it is assumed that the oil relative permeability is a function of oil saturation alone during the analysis of a given run, this function is not necessarily same in all runs. Actually the results of the run determine the shape of this function. The experiments involved displacement of oil by simultaneous injection of gas and water. The physics of the displacements was such that at any point in the core the oil saturation would be monotone decreasing with time. Furthermore, since the ratio of water and gas in the injected phase was fixed, the ratio of gas and water saturations would not be expected to vary too much within the core after the breakthrough of the displacing fluids. Therefore, the displacement path on the triangular diagram can be approximated by a straight line. Along this line the relative permeability to each phase would be a function of its own saturation since specifying one saturation on this line defines all saturations.

COMPARISON OF UNSTEADY-STATE AND STEADY-STATE RESULTS:

Figure 25 compares the oil isoperms obtained by the unsteady-state method with those obtained earlier with the steady-state technique. Considering the experimental errors involved in the two sets of measurements, the agreement is quite good. A serious problem encountered in the unsteady-state experiments was due to the compressibility of the gas which caused unwanted variations in the gas injection rate. It is likely that the unsteady-state technique can be improved further by improving the gas injection apparatus.

CONCLUSIONS

The following conclusions can be drawn from the work discussed in this report.

1. An improved apparatus for measuring three-phase relative permeabilities at elevated temperatures and pressures has been developed. The resistivity based in-situ measurement of water saturation and inclusion of the end effect absorbing section in the sand pack resulted in significantly improved reliability of the measurements.

2. Steady-state three-phase relative permeabilities measurements were carried out in direction of decreasing and increasing oil saturations.

3. The new experimental data fitted the modified Stone's method I correlation quite well.

4. An unsteady-state technique for three-phase relative permeability measurements was developed and tested.

5. The oil isoperms measured by the unsteady-state technique were similar to those obtained by the steady-state method.

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Table 1a: Properties of the Core Used for Relative Permeability Tests in Silica Sand.

Type of sand:	140-200 mesh silica sand
Core length:	46.7 cm
Cross-sectional area:	25 cm^2
Pore volume:	409 ml
Absolute permeability:	3.6 Darcy
Confining pressure:	10.3 MPa.
Pore pressure	3.45 MPa.

Table 1b: Properties of Mineral Oil used in Relative Permeability Measurements.

Temperature (°C)	23	100	200
Density (g/ml)	0.877	0.828	0.767
Viscosity (mPa.s)	405.0	12.0	2.3

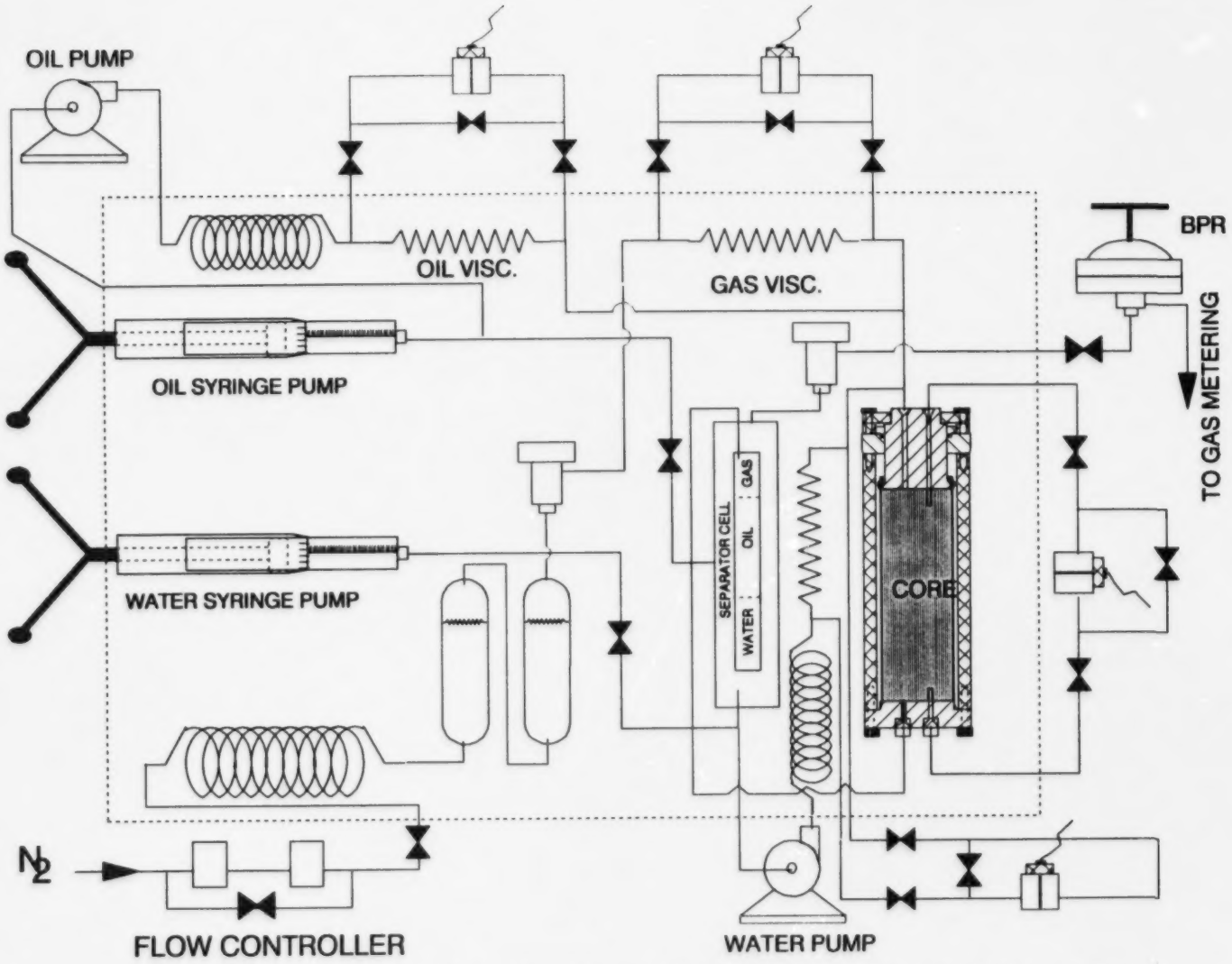


Figure 1: Schematic diagram of the original equipment

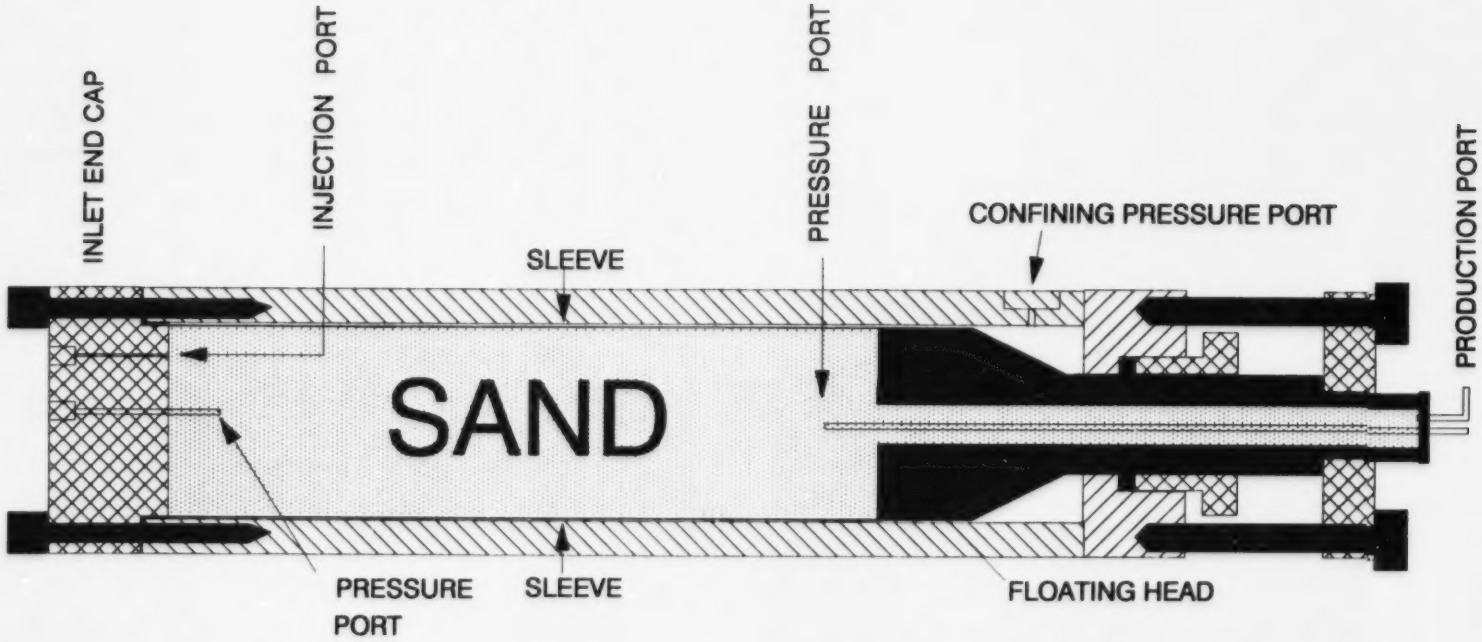


Figure 2: Modified core holder design incorporating an end-effect absorbing section

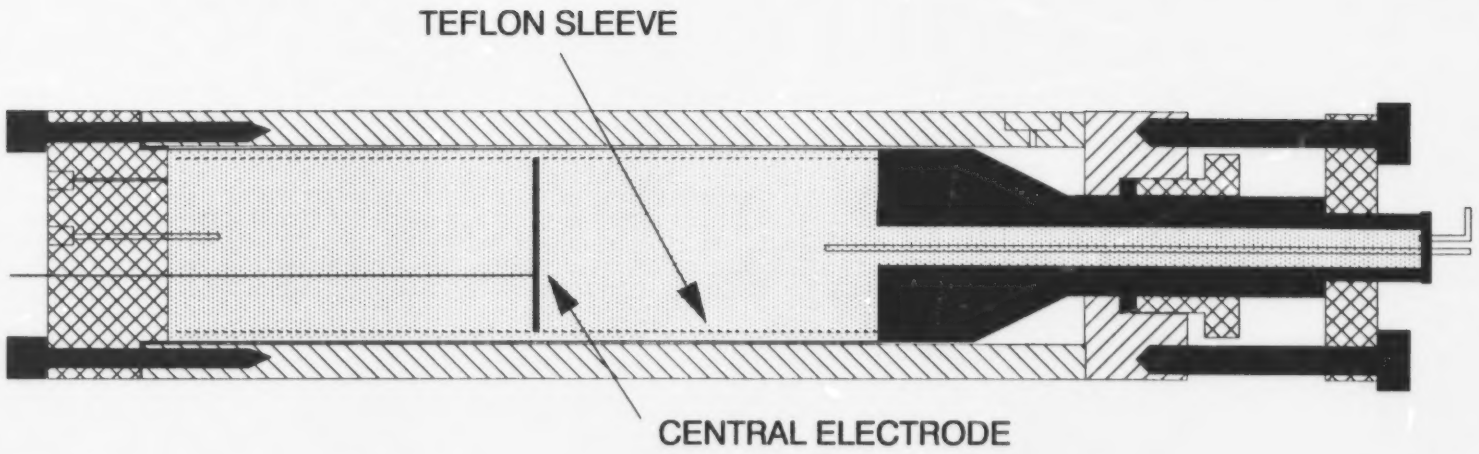


Figure 3: Schematic diagram showing the placement of a central electrode and the teflon sleeve

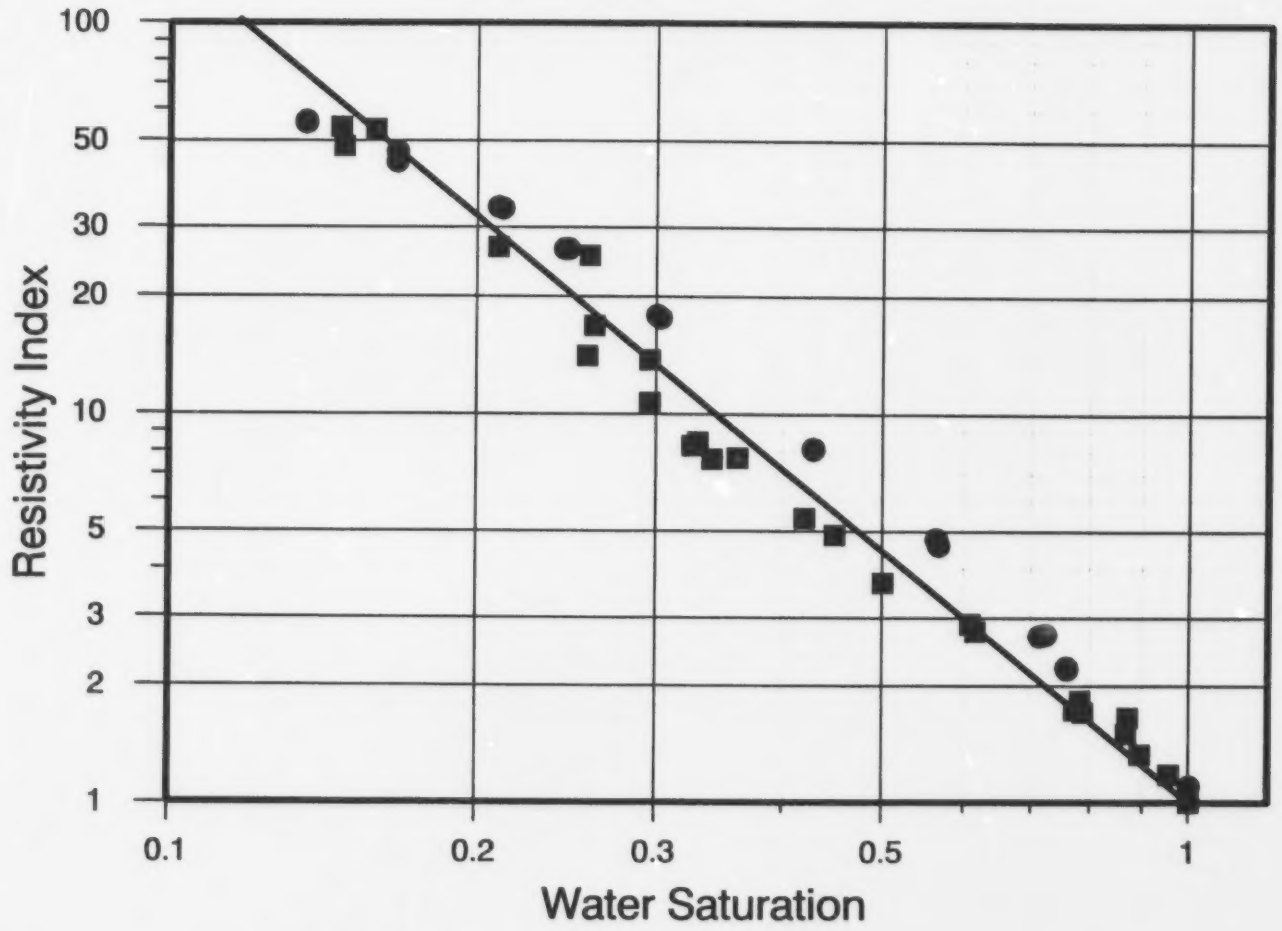


Figure 4: Relationship between resistivity index and water saturation.

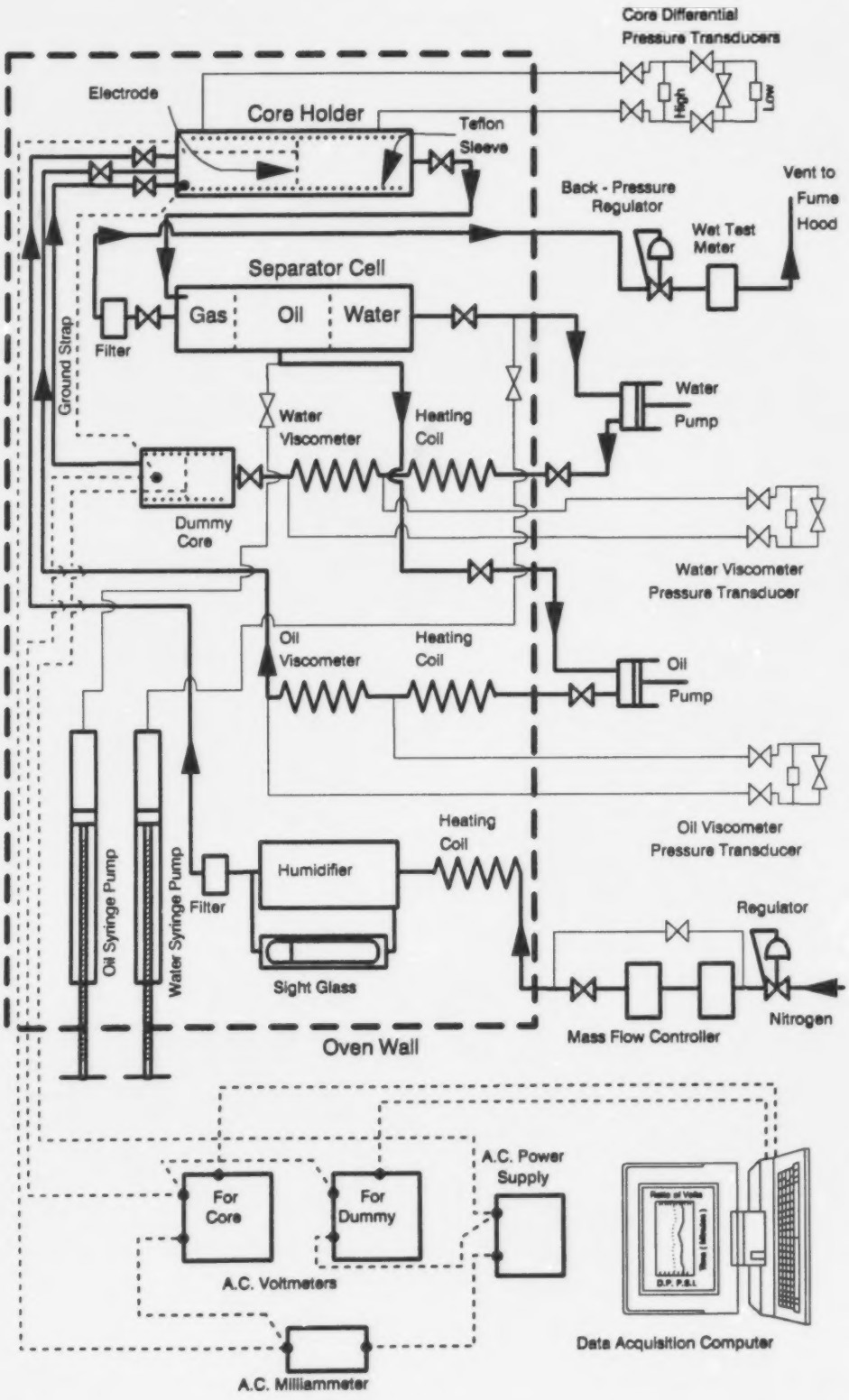


Figure 5: Schematic diagram of the improved equipment

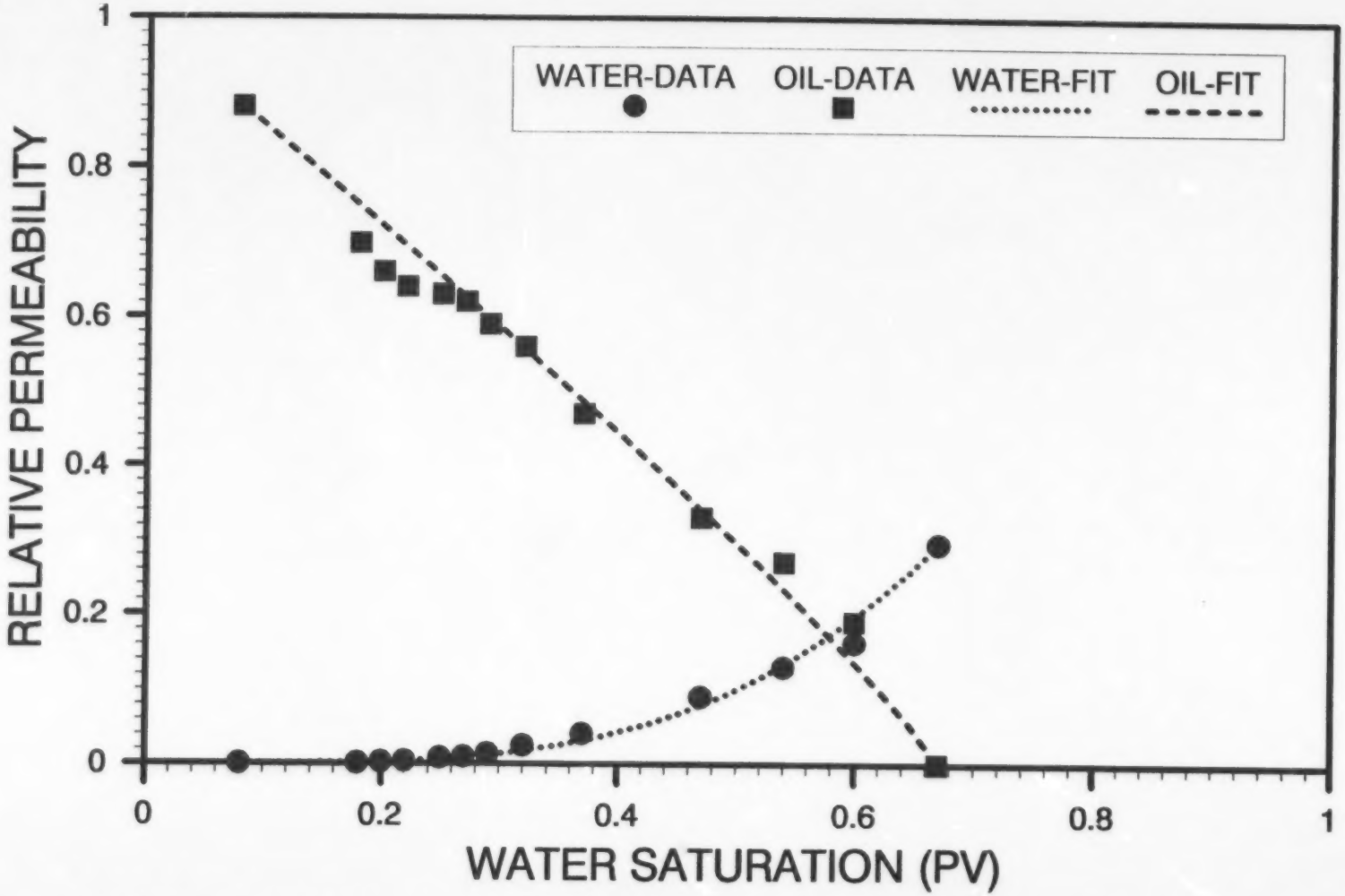


FIGURE 6: TWO-PHASE OIL/WATER RELATIVE PERMEABILITIES IN IMBIBITION DIRECTION (OIL SAT. DECREASING)

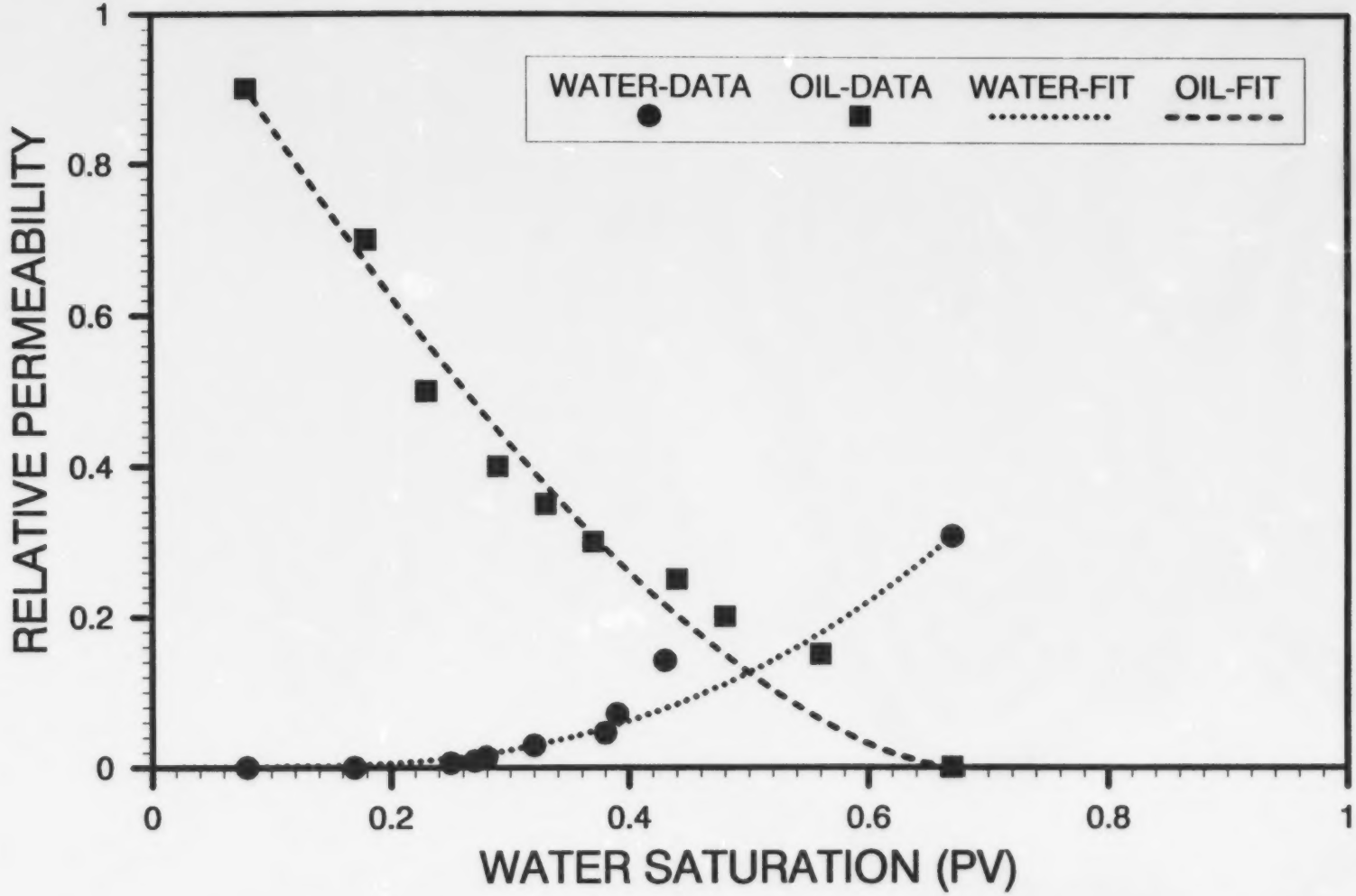


FIGURE 7: TWO-PHASE OIL/WATER RELATIVE PERMEABILITIES IN DRAINAGE DIRECTION (OIL SAT. INCREASING)

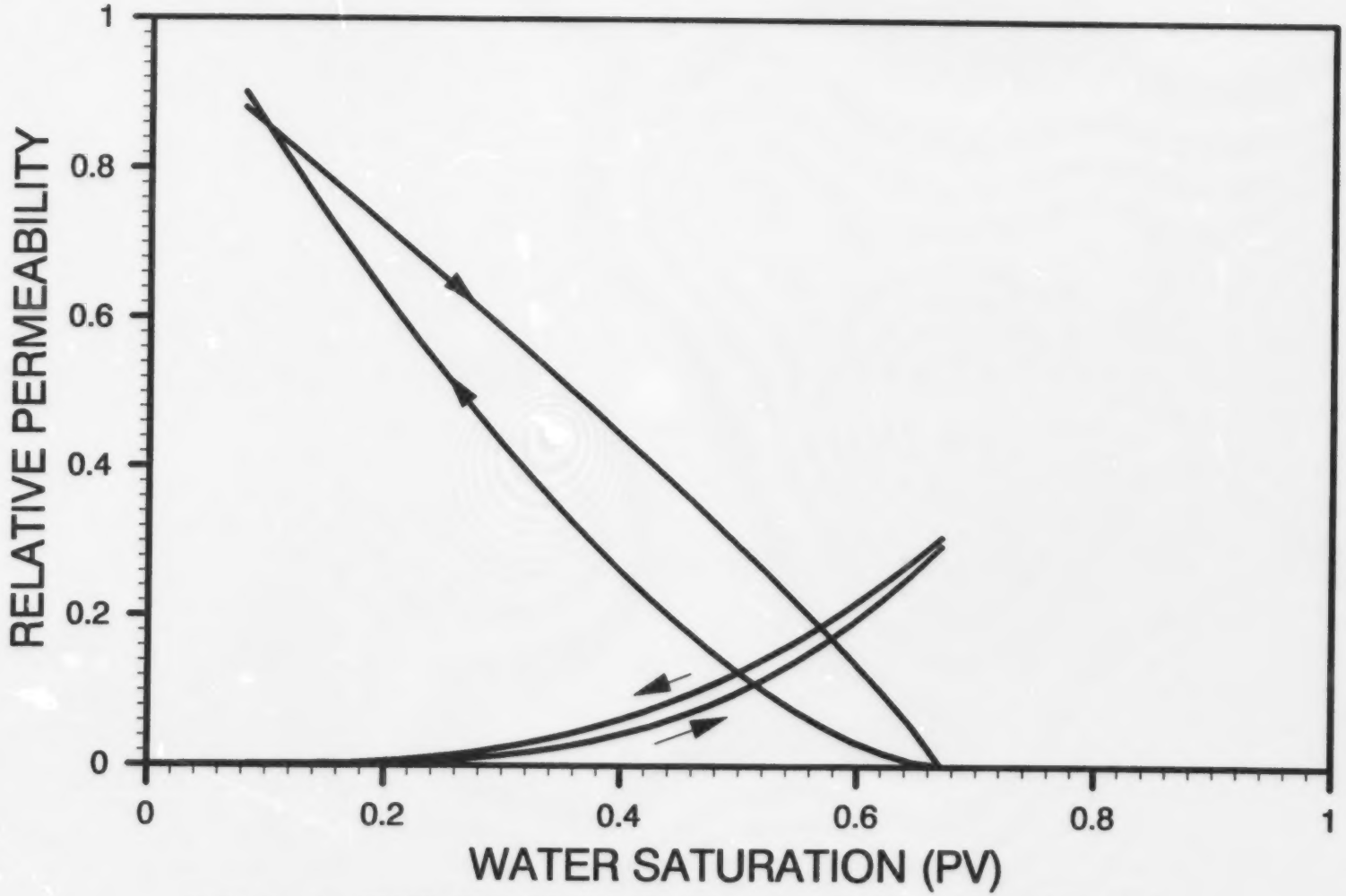


FIGURE 8: TWO-PHASE OIL/WATER RELATIVE PERMEABILITY HYSTERESIS

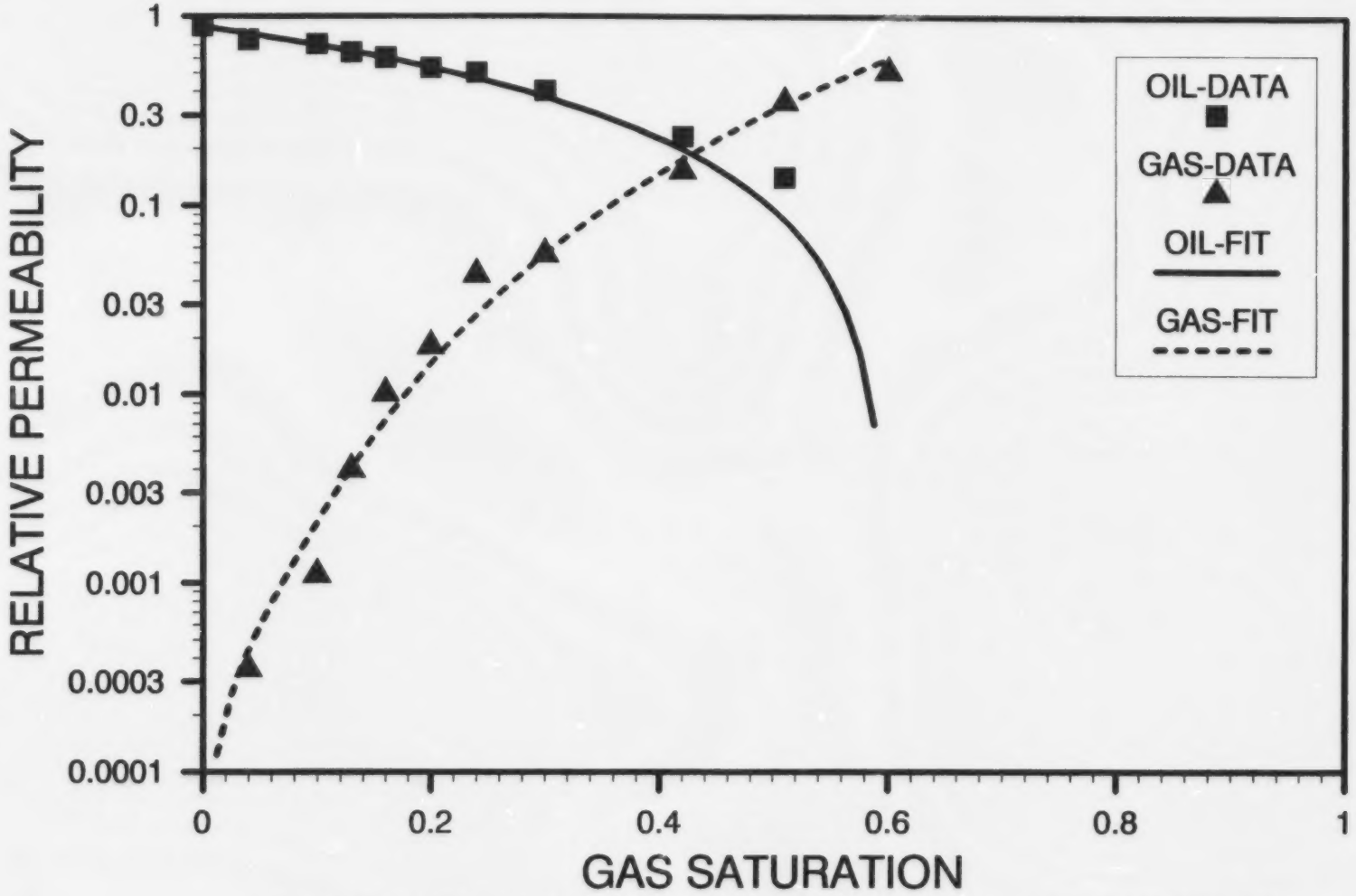


FIGURE 9: TWO-PHASE OIL/GAS REL. PERMS. IN DIRECTION OF DECREASING OIL SATURATION

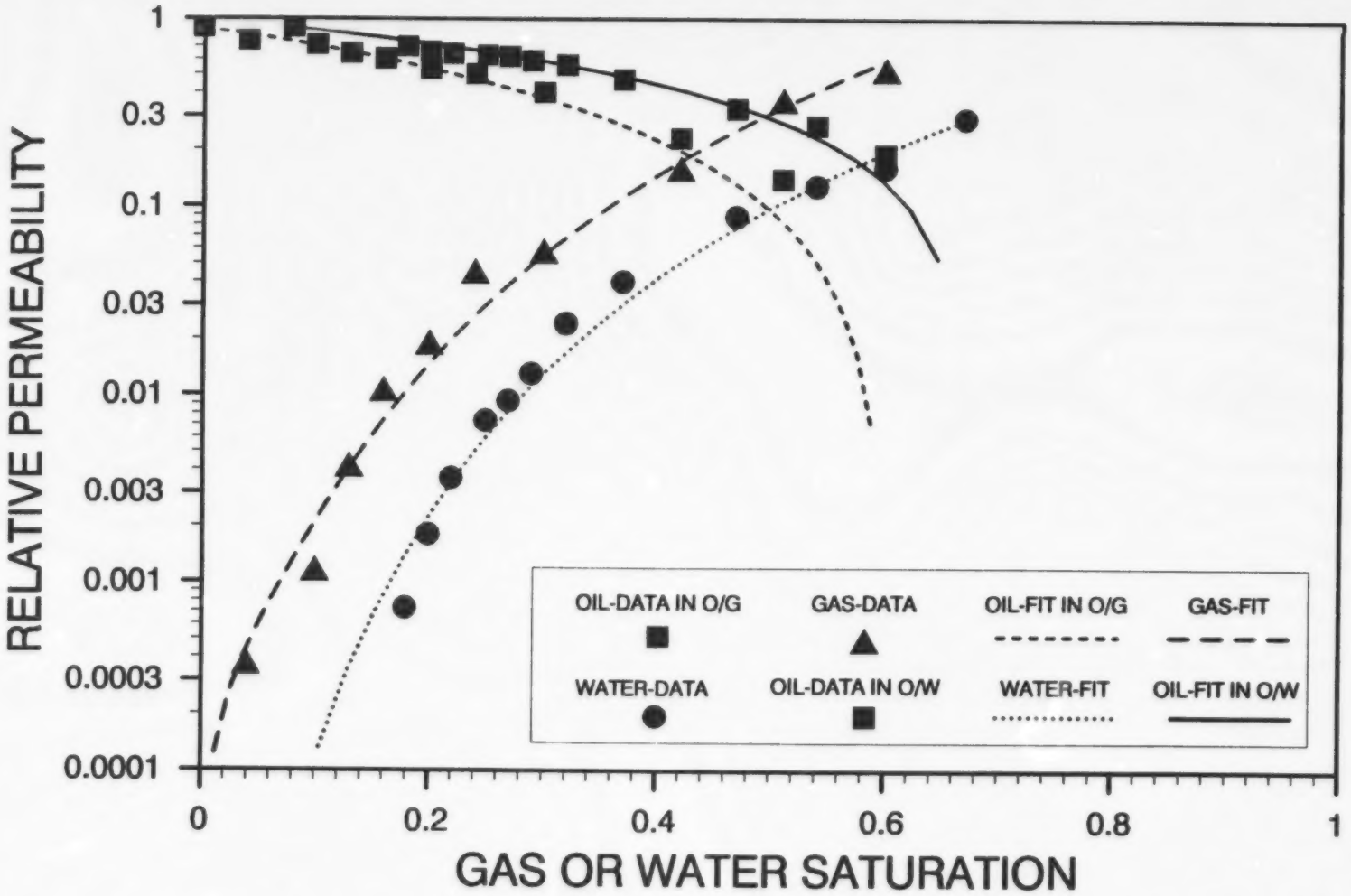


FIGURE 10: TWO-PHASE OIL/WATER AND OIL/GAS REL. PERMS. IN DIRECTION OF DECREASING OIL SATURATION

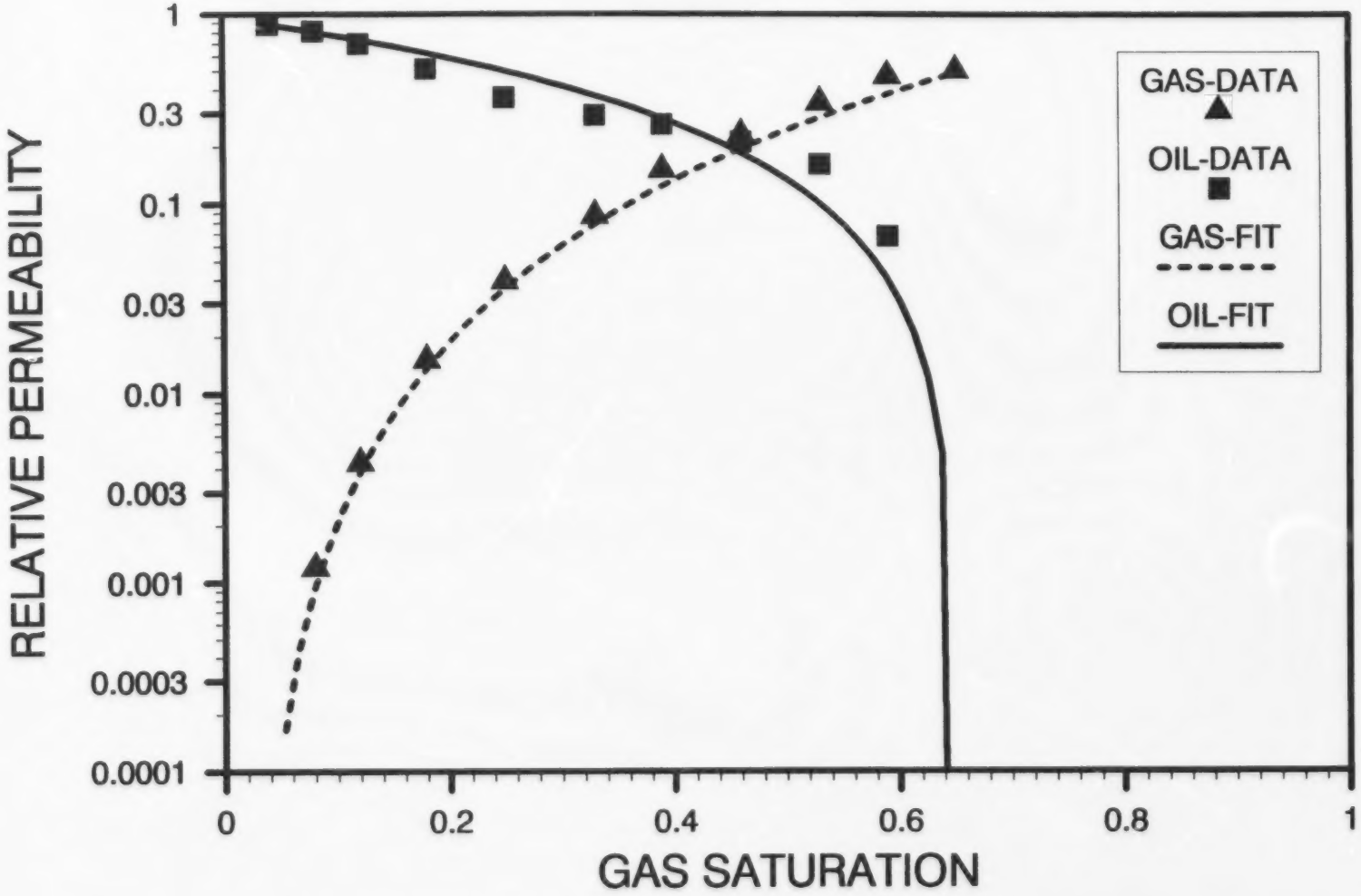


FIGURE 11: TWO-PHASE OIL/GAS REL. PERMS.IN DIRECTION OF INCREASING OIL SATURATION

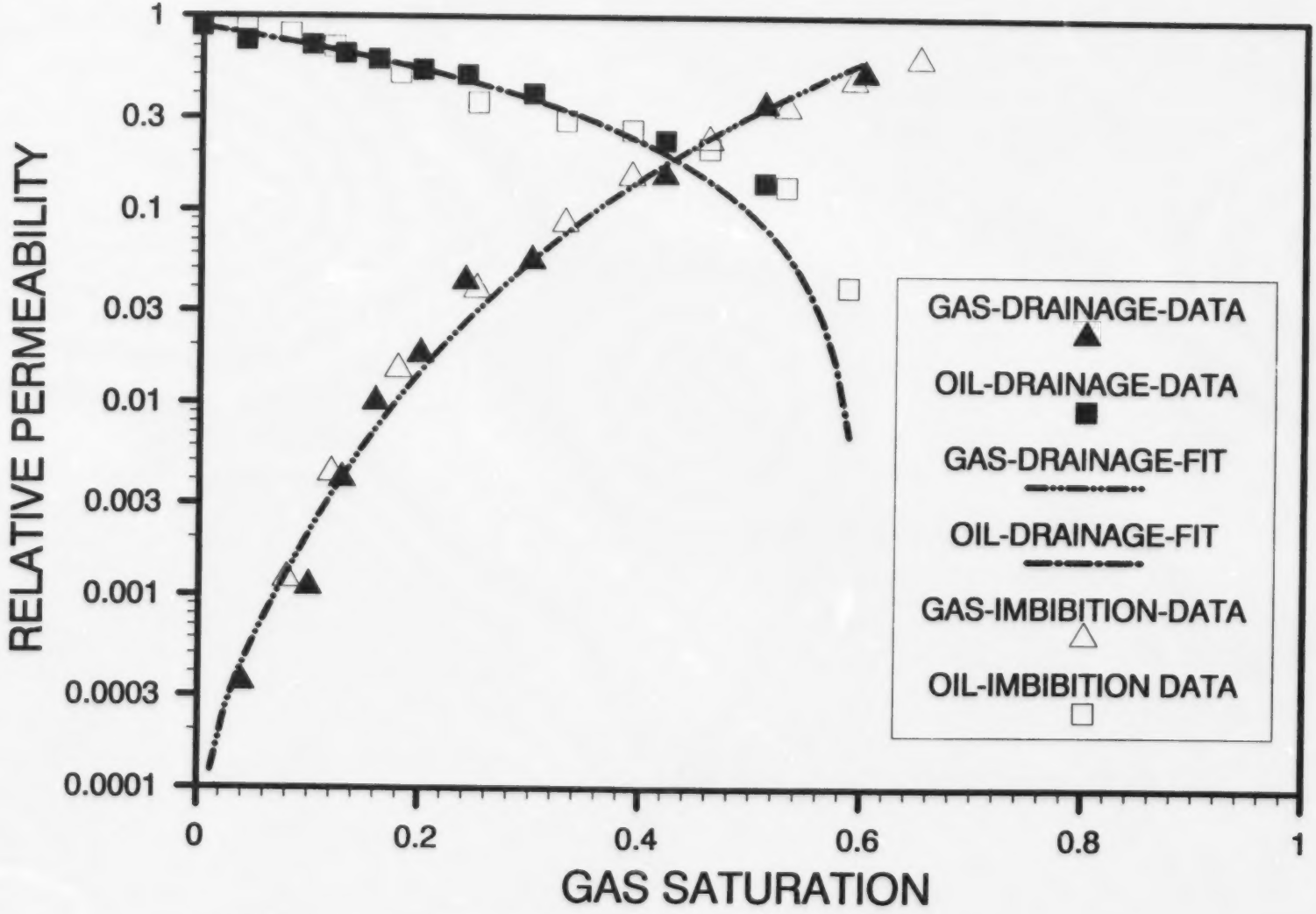


FIGURE 12: TWO-PHASE OIL/GAS REL. PERM. HYSTERESIS

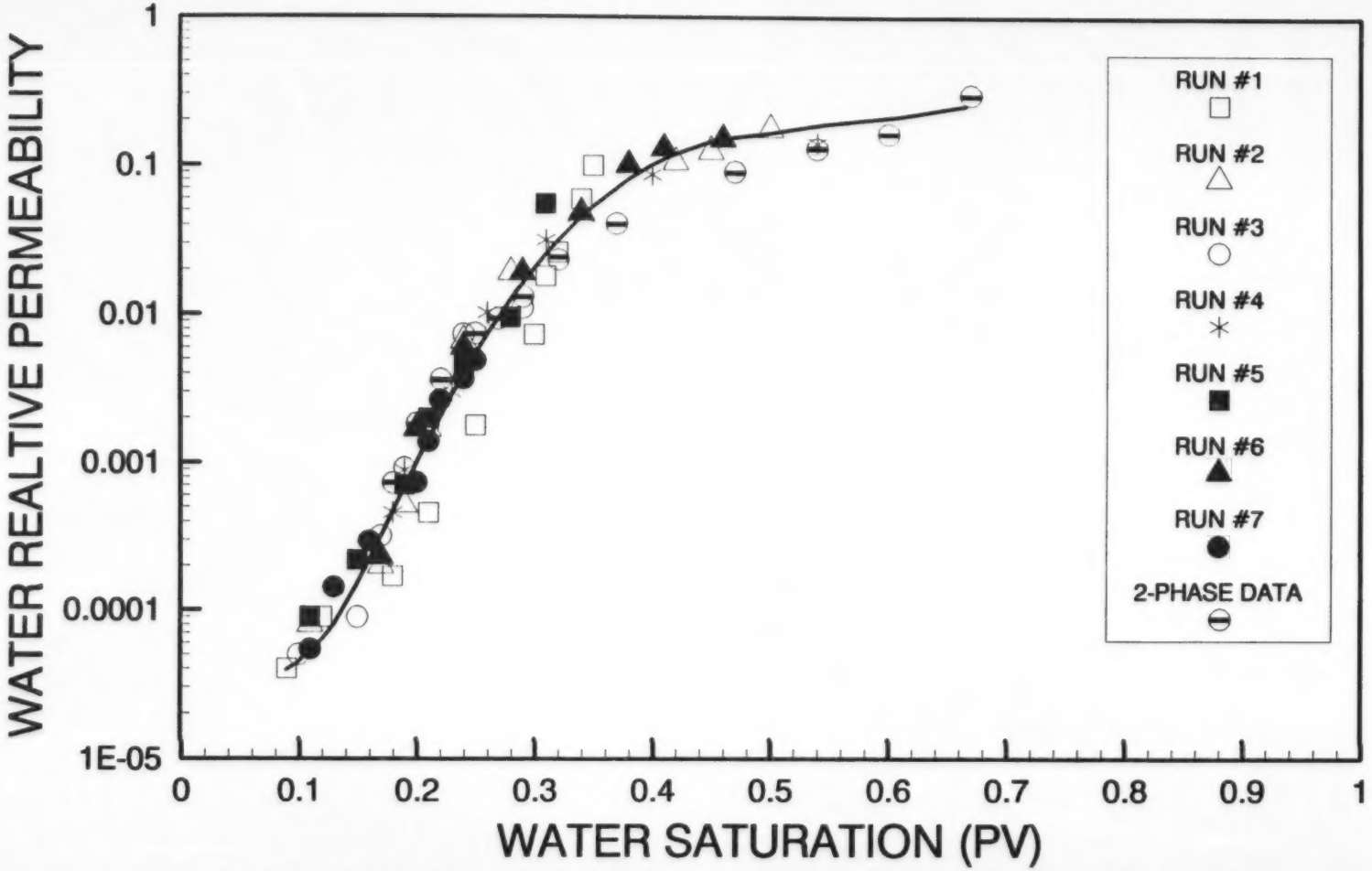


FIGURE 13: THREE-PHASE WATER RELATIVE PERMEABILITIES
IN IMBIBITION DIRECTION
(Sw and Sg increasing, So decreasing)

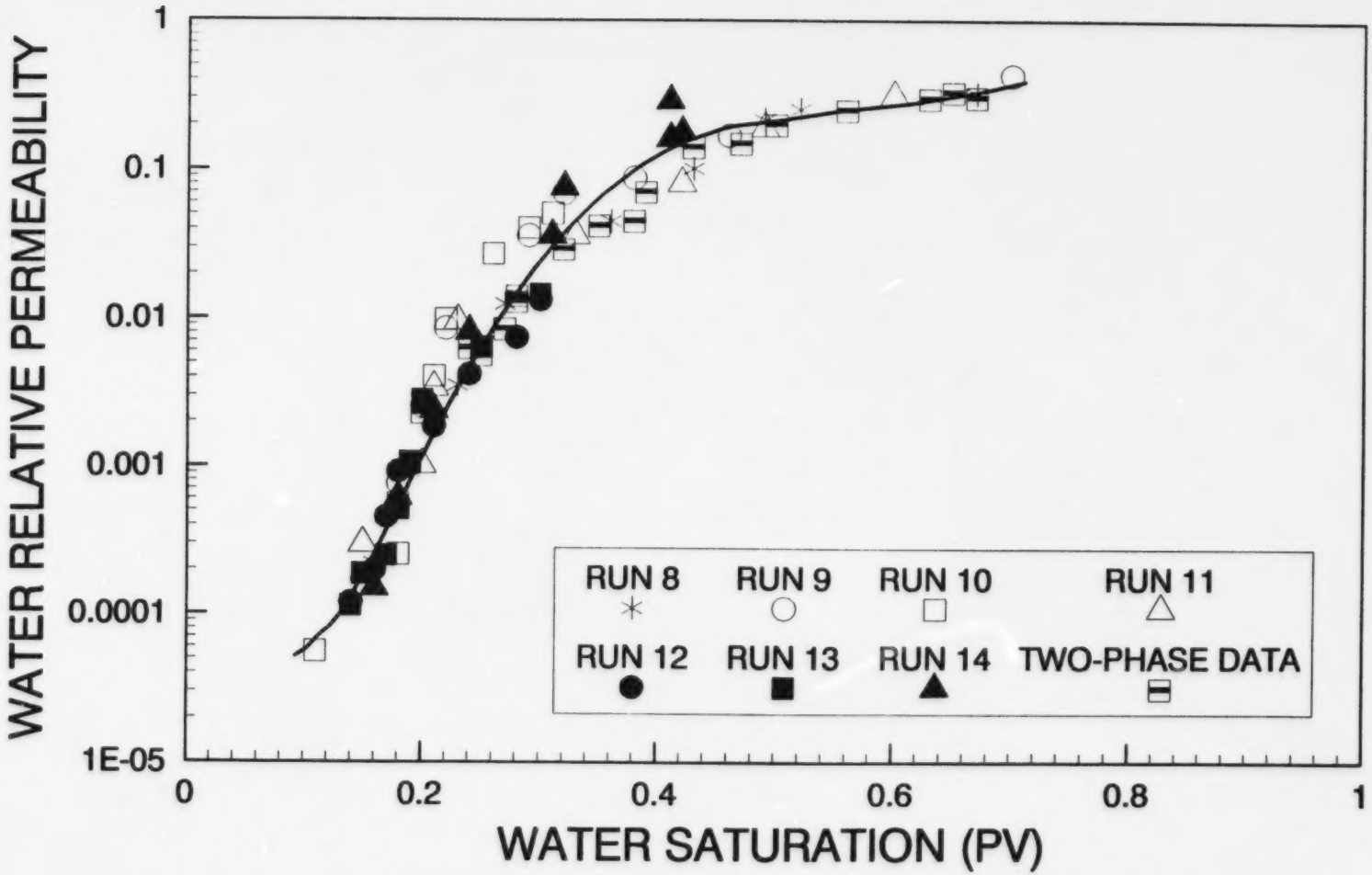


FIGURE 14: THREE-PHASE WATER RELATIVE PERMEABILITIES
IN DRAINAGE DIRECTION
(Sw and Sg decreasing, So increasing)

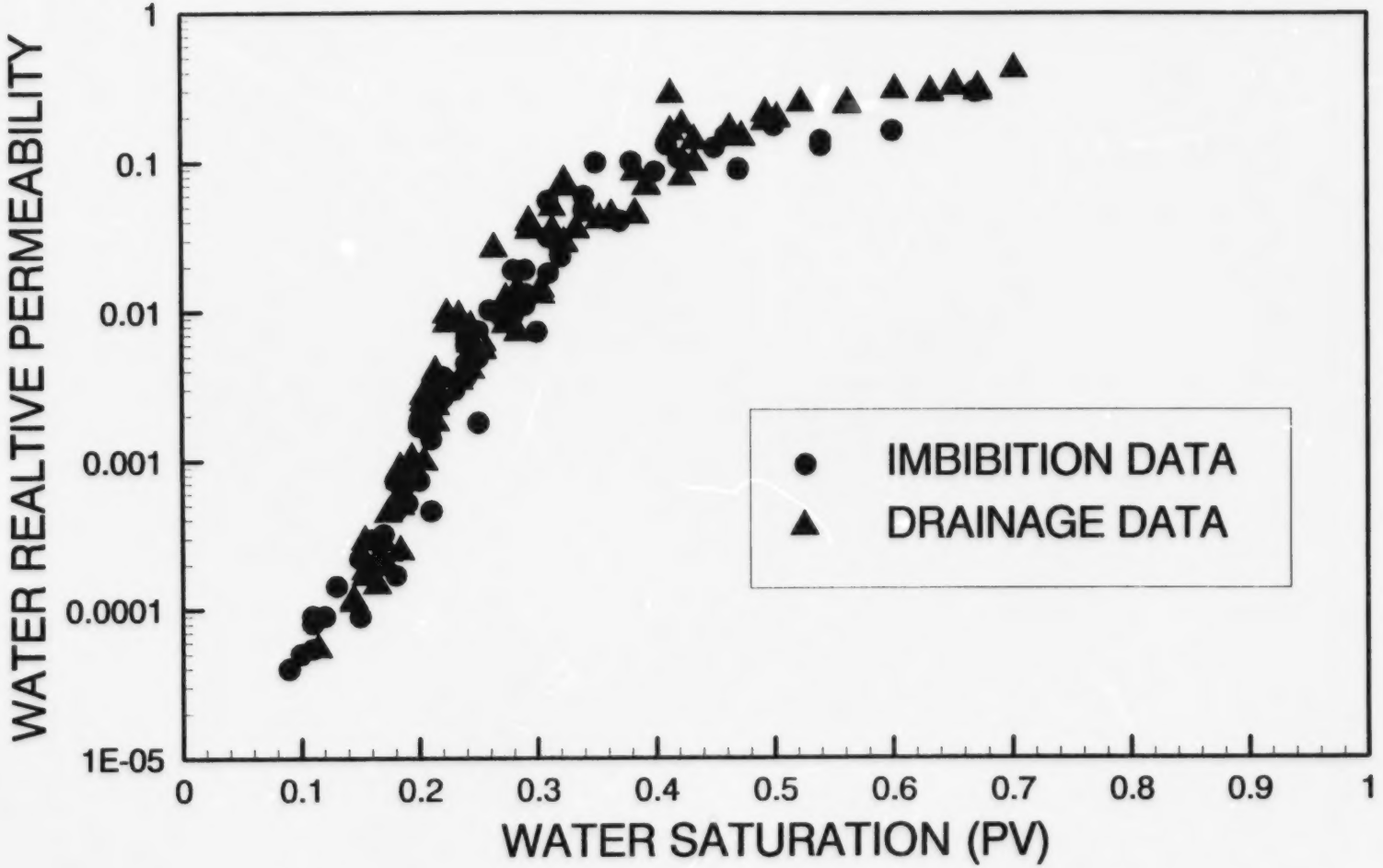


FIGURE 15: THREE-PHASE WATER RELATIVE PERMEABILITY HYSTERESIS

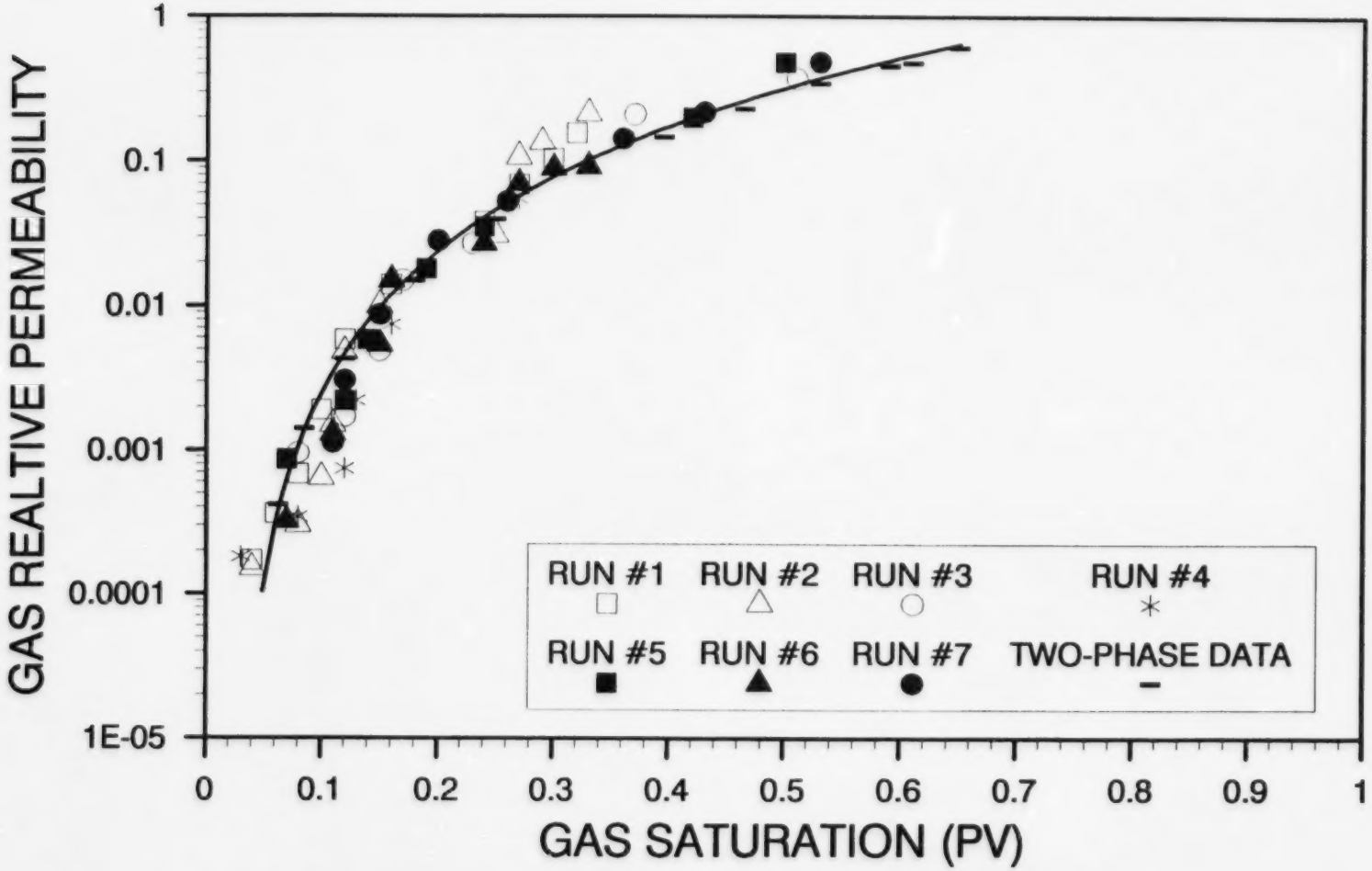


FIGURE 16: THREE-PHASE GAS RELATIVE PERMEABILITIES
IN IMBIBITION DIRECTION
(Sw and Sg increasing, So decreasing)

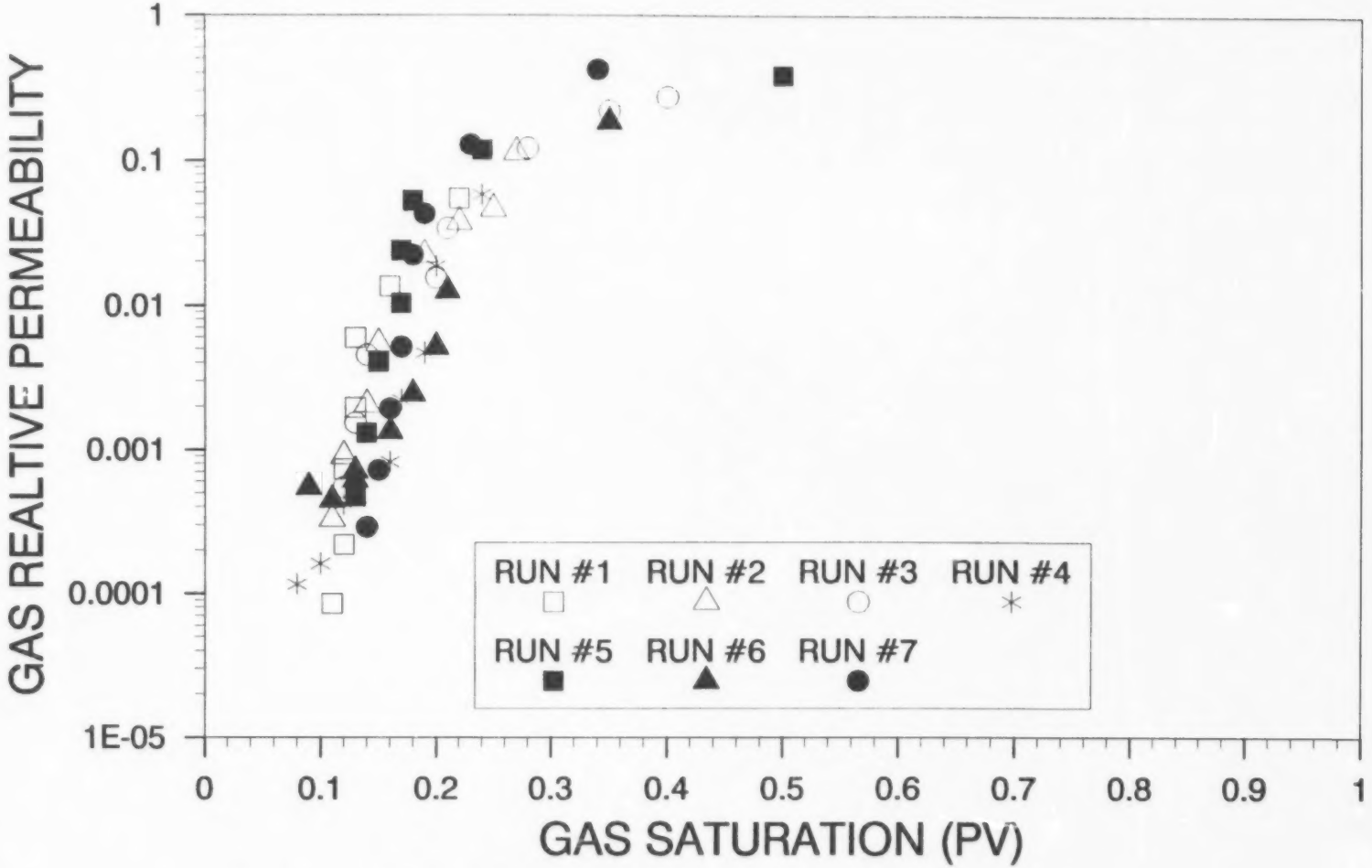
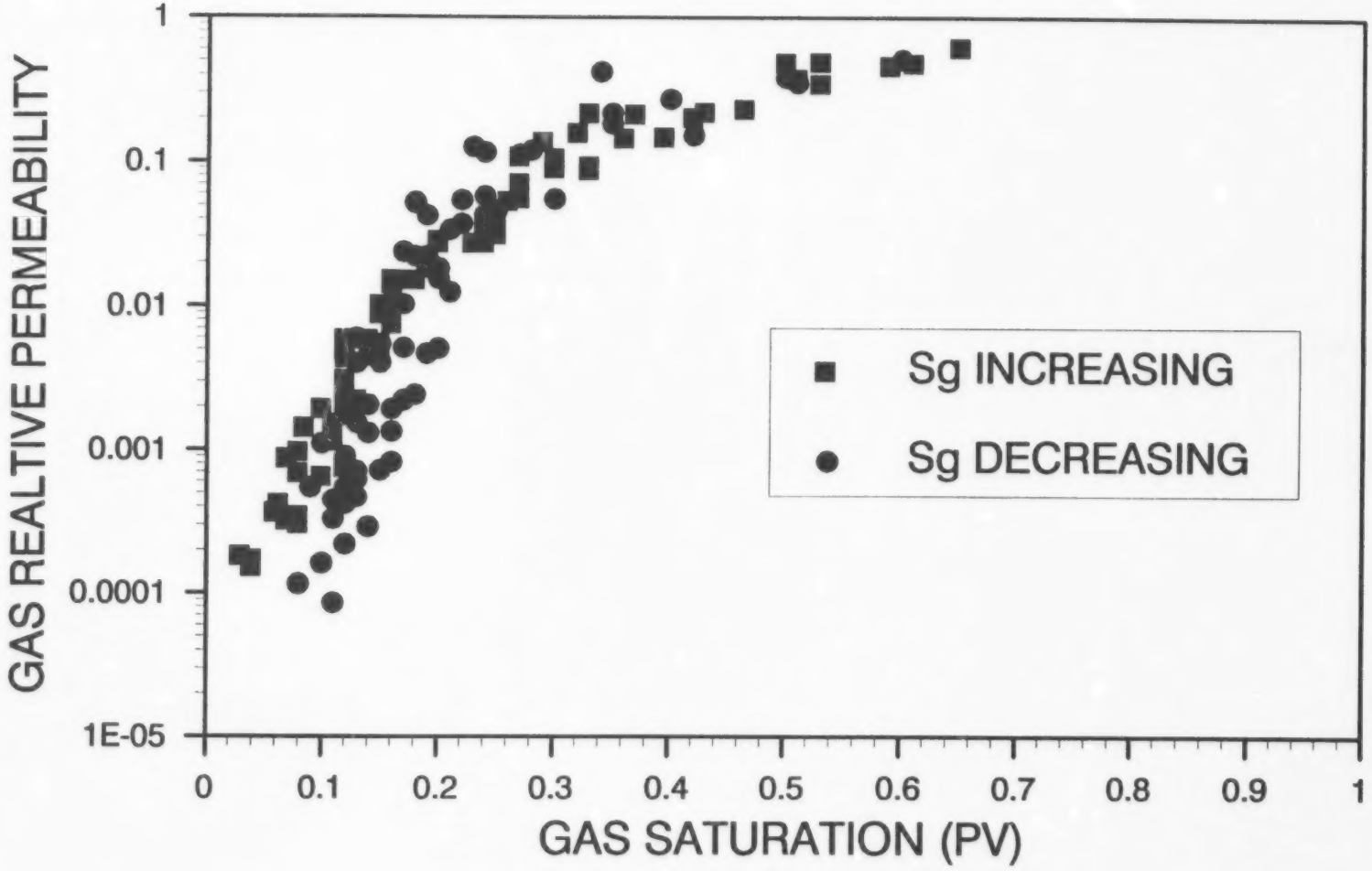


FIGURE 17: THREE-PHASE GAS RELATIVE PERMEABILITIES
IN DRAINAGE DIRECTION
(Sw and Sg decreasing, So increasing)



FIHURE 18: HYSTERESIS IN THREE-PHASE GAS RELATIVE PERMEABILITY

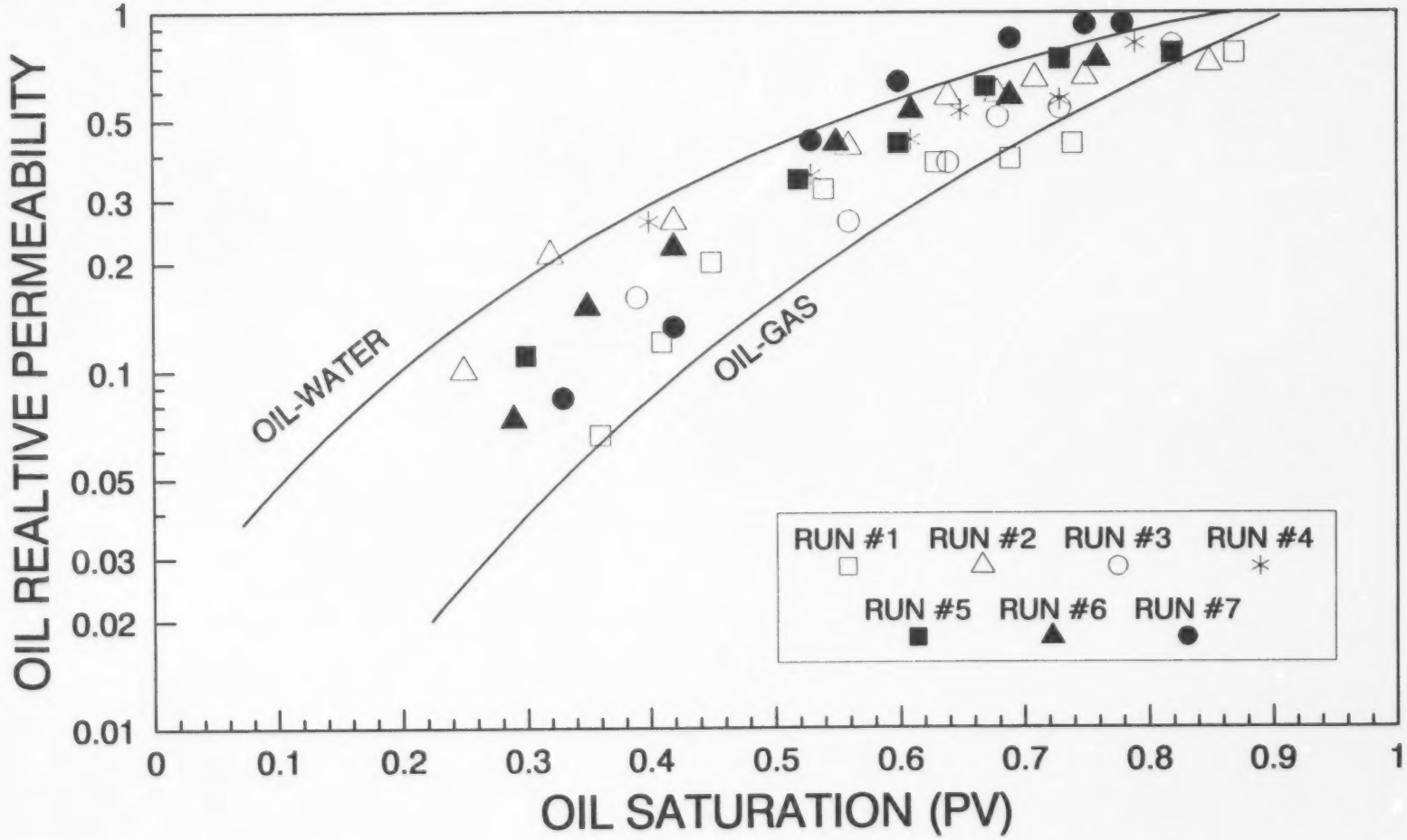


FIGURE 19: THREE-PHASE OIL RELATIVE PERMEABILITIES
IN IMBIBITION DIRECTION
(Sw and Sg increasing, So decreasing)

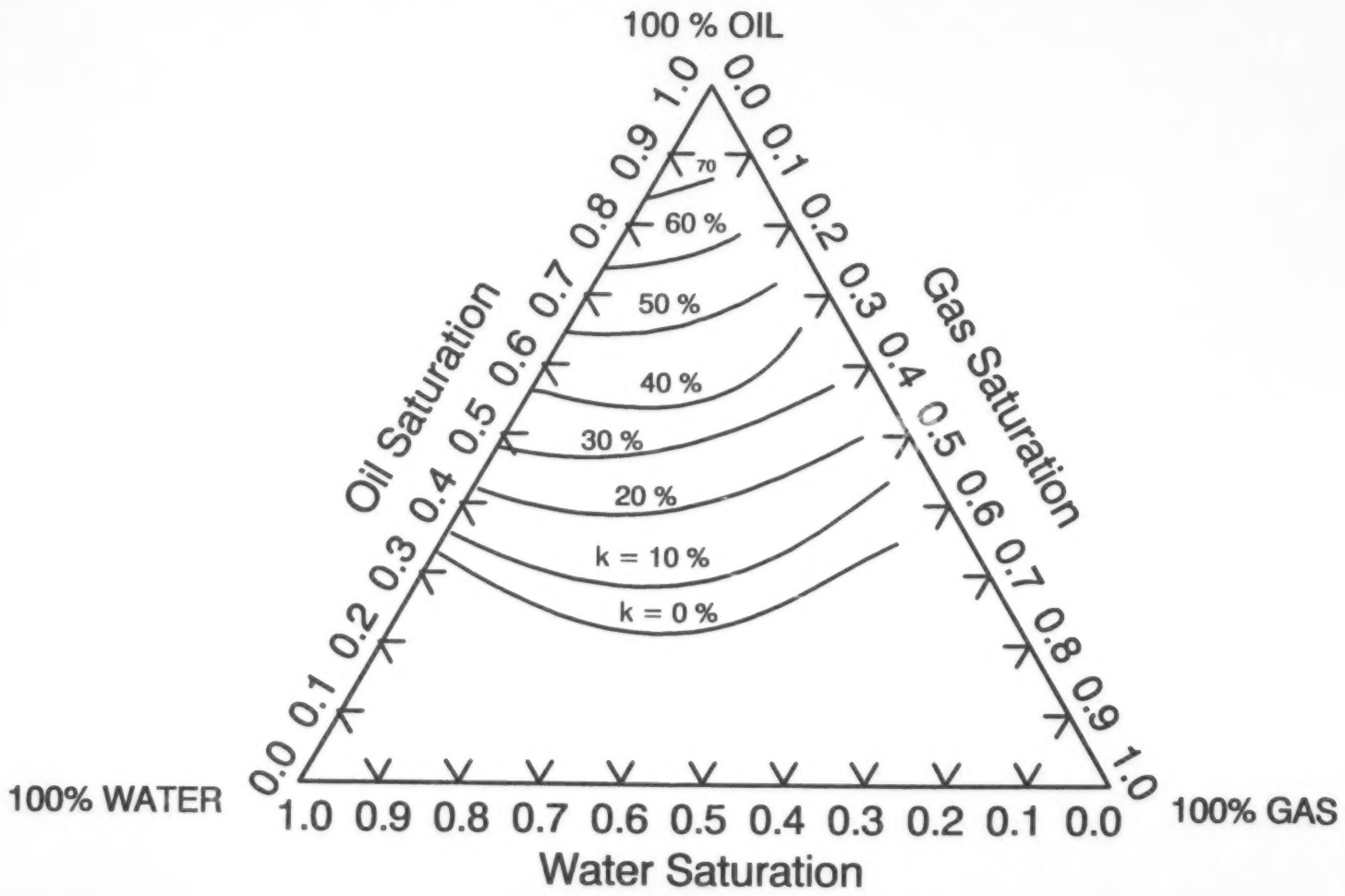


Figure 20: Three-phase oil relative permeability in direction of decreasing oil saturation.

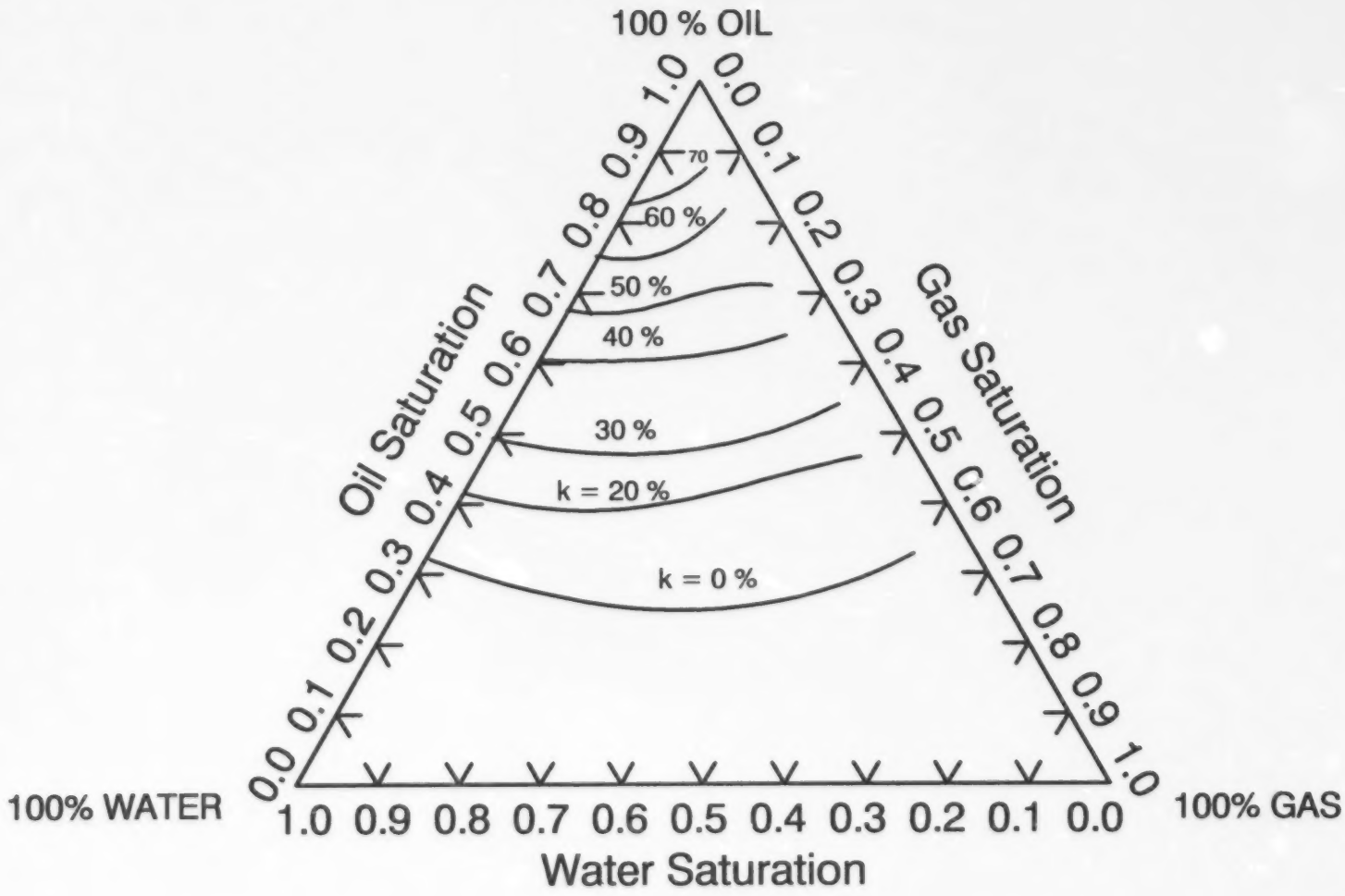


Figure 21: Three-phase oil relative permeability in direction of increasing oil saturation.

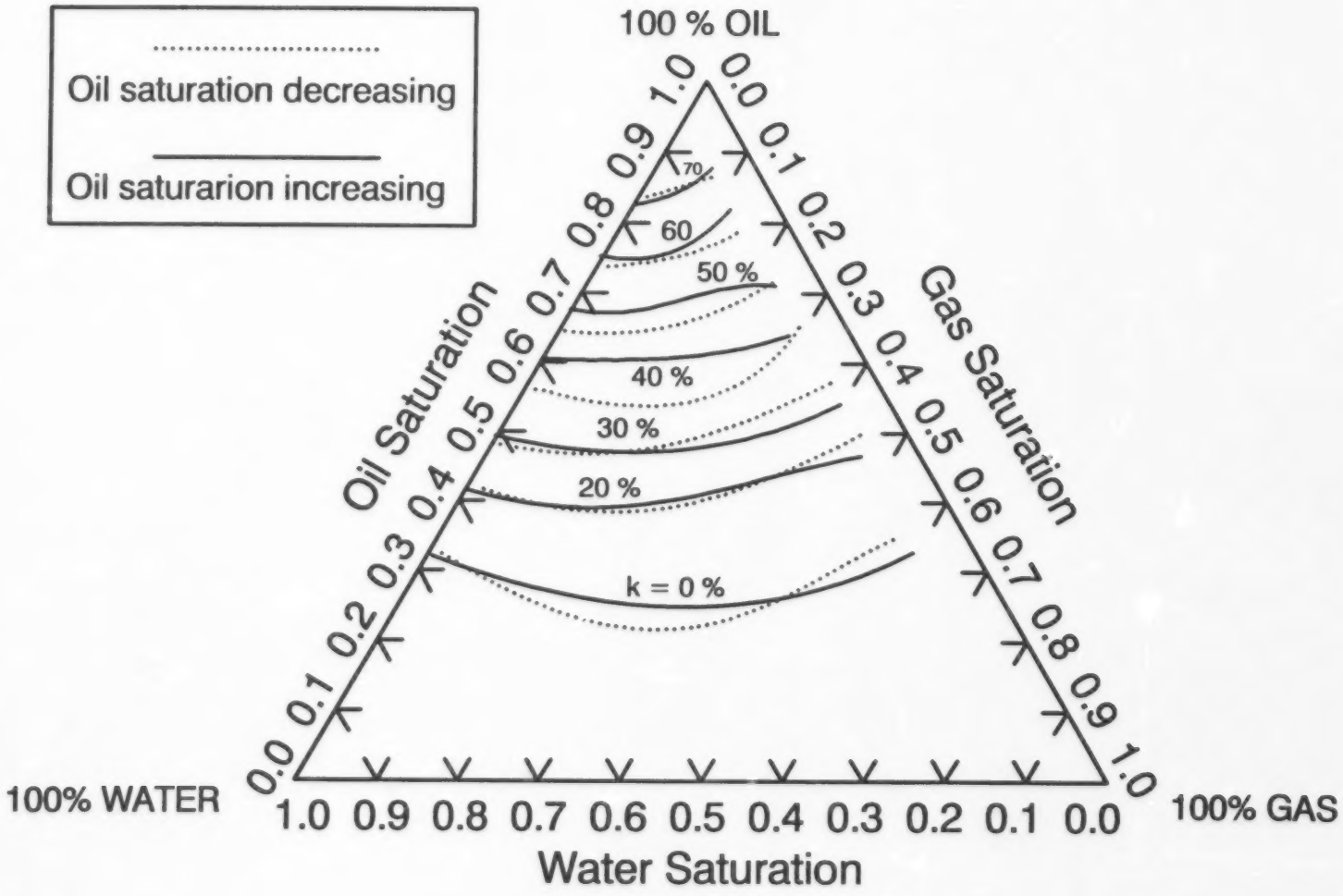


Figure 22: Hysteresis in three-phase oil relative permeability.

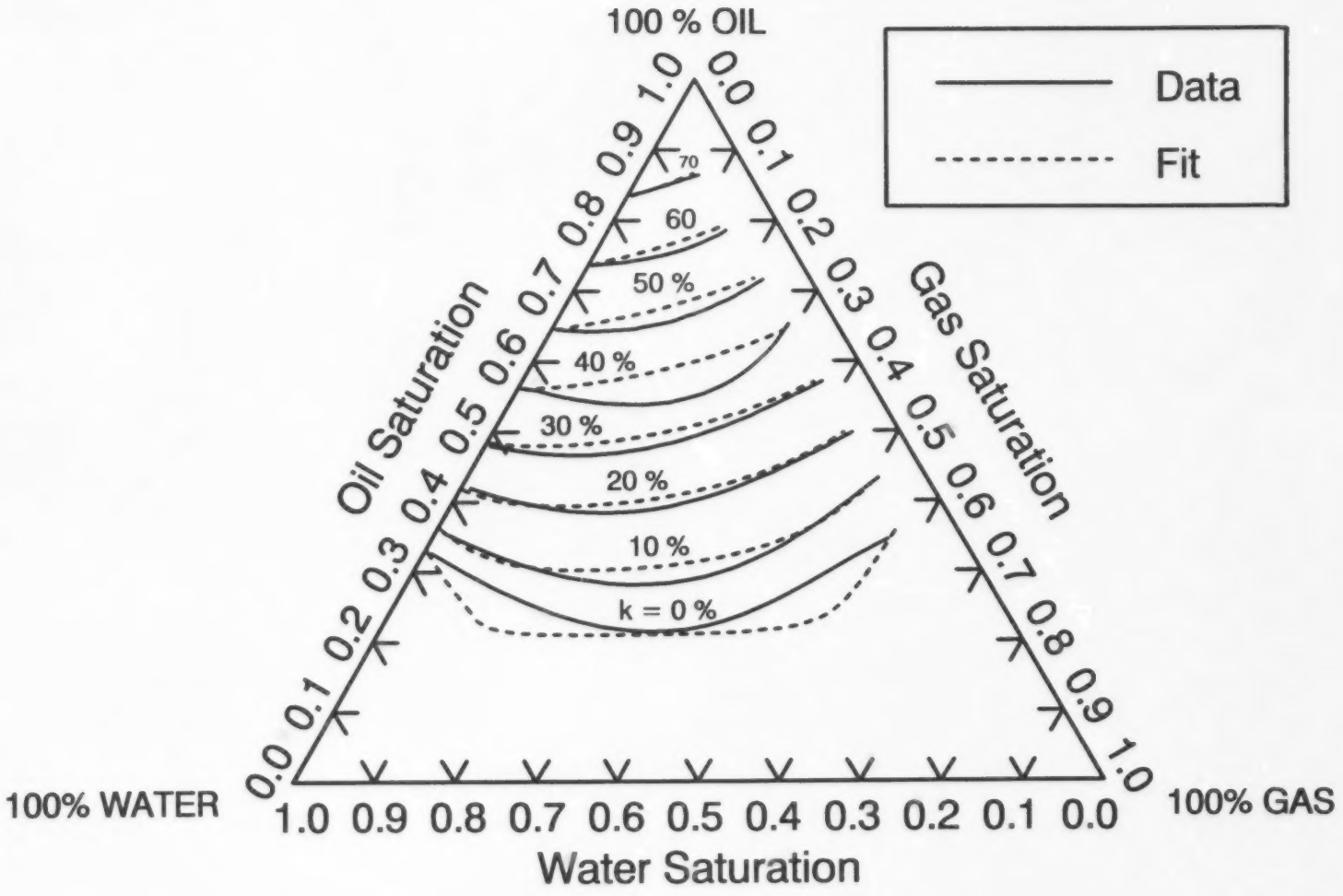


Figure 23: Fit of Imbibition Data with Modified Stone I

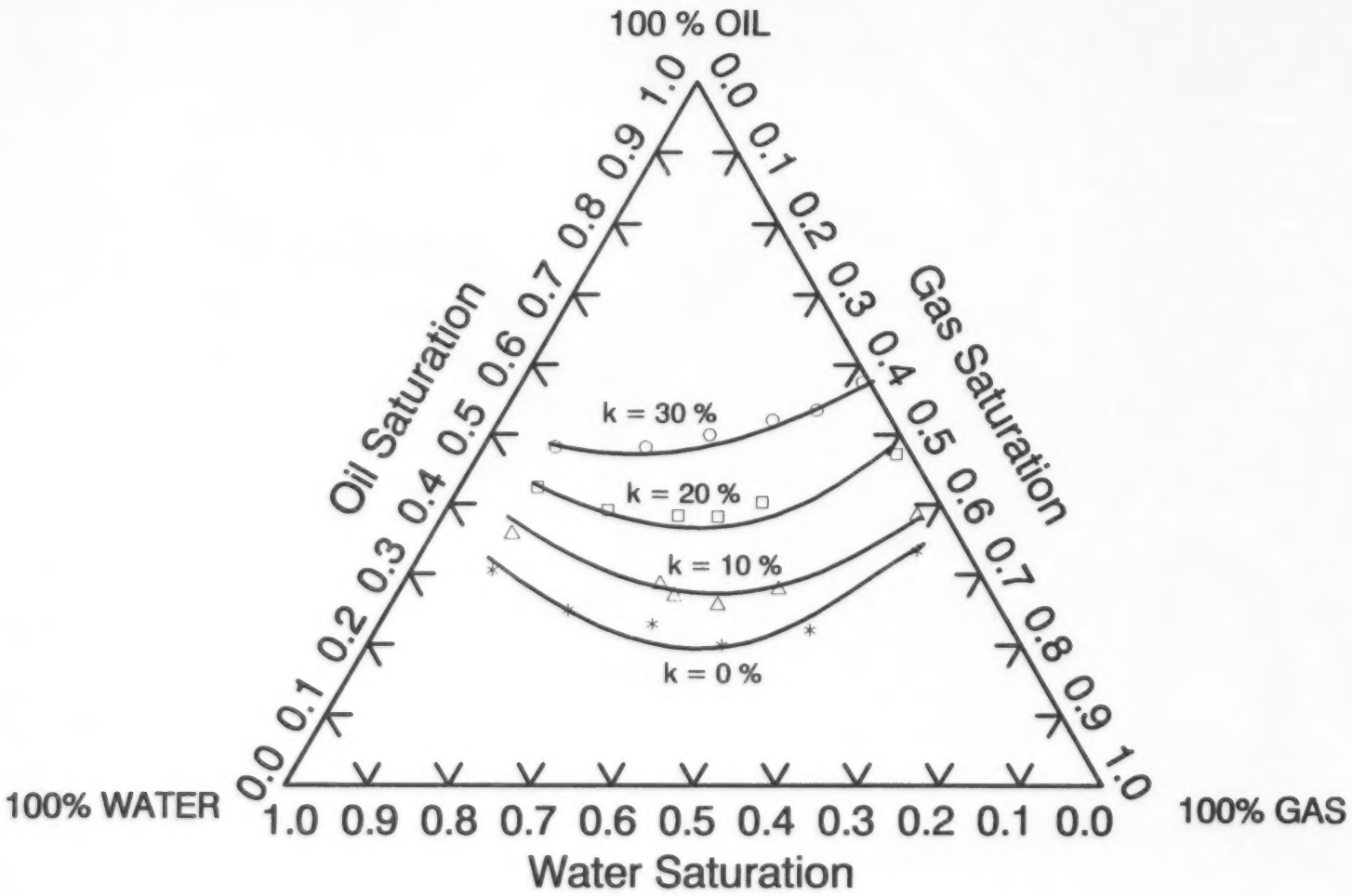


Figure 24: Oil isoperms as measured by the unsteady-state technique

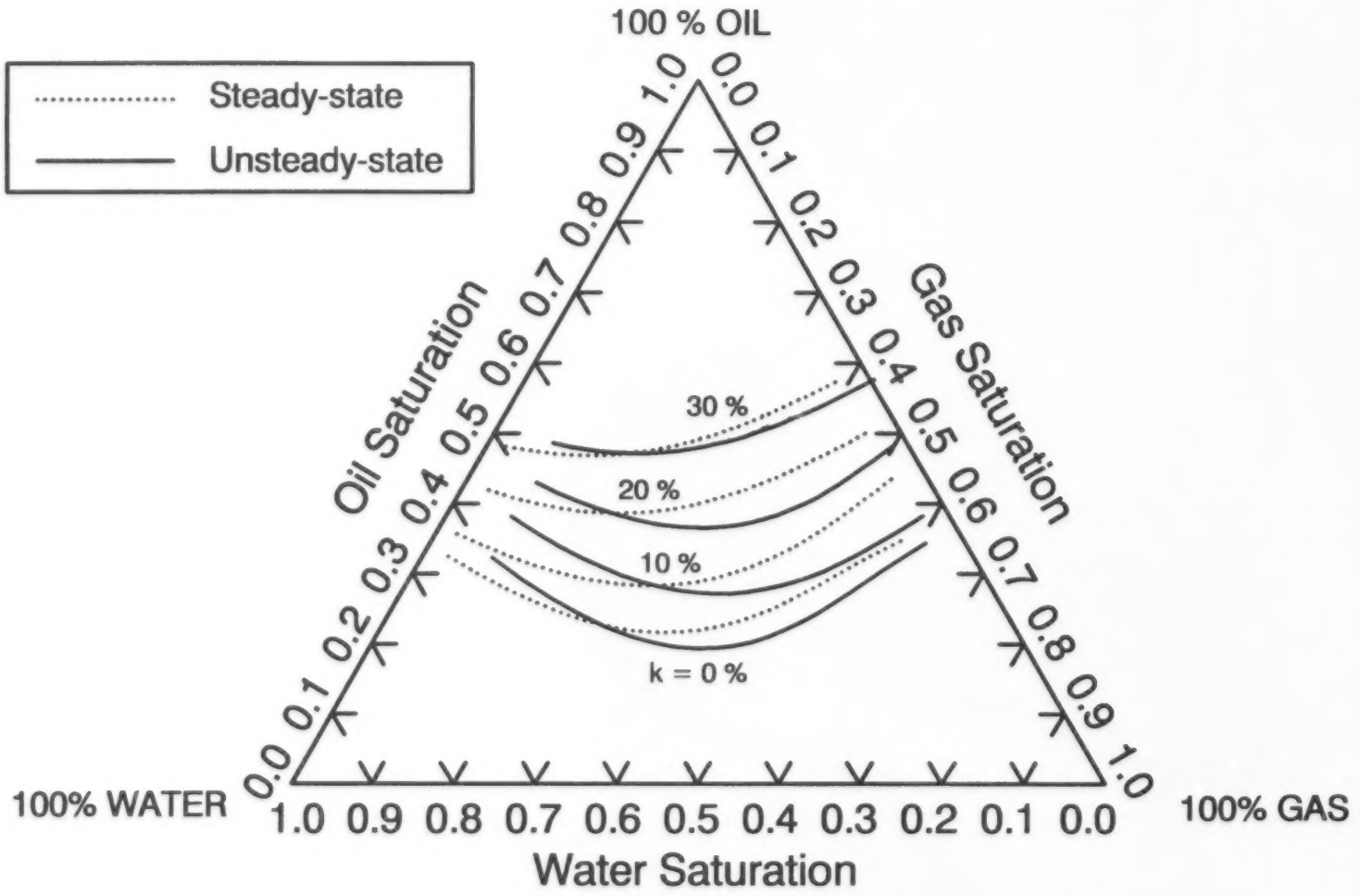


Figure 25: Comparison of steady-state and unsteady-state oil isoperms